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A cumulative list of the parts affected this month can be found in the Reader Aids section at the end of this issue.

Rules and Regulations

Federal Register

Vol. 72, No. 50

Thursday, March 15, 2007

OFFICE OF PERSONNEL MANAGEMENT

5 CFR PART 211

RIN 3206–AL00

Veterans' Preference

AGENCY: Office of Personnel Management.

ACTION: Final rule.

SUMMARY: The Office of Personnel Management (OPM) is adopting as a final rule, without changes, an interim rule that implemented amendments to veterans' preference as contained in the National Defense Authorization Act for FY 2006. These amendments expanded the definition of a veteran and clarified veterans' preference eligibility for individuals discharged or released from active duty under honorable conditions. The intended effect of the regulatory changes was to conform OPM's regulations to the changes in the veterans' preference laws, to ensure that job-seeking veterans received the preference to which they are entitled.

DATES: Final rule effective March 15, 2007.

FOR FURTHER INFORMATION CONTACT: Scott A. Wilander by telephone at (202) 606–0960; by fax at (202) 606–0390; TTY at (202) 606–3134; or by e-mail at *Scott.Wilander@opm.gov*.

SUPPLEMENTARY INFORMATION: On June 9, 2006, OPM issued an interim rule with request for comments at 71 FR 33375, to amend its regulation for implementing statutory changes regarding veterans' preference. This rule: (1) Expanded the definition of a veteran in 5 CFR 211.102(a) to include individuals who served on active duty for more than 180 consecutive days, other than for training, any part of which occurred during the period beginning September 11, 2001, and ending on the date prescribed by Presidential proclamation or by law as the last day of Operation Iraqi Freedom; (2) revised § 211.102(a) to include anyone who served on active duty during the period beginning August 2, 1990, and ending January 2, 1992, as previously established by the National Defense Authorization Act for Fiscal Year 1998 (Public Law 105–85); (3) clarified that individuals who are released or discharged from active duty in the armed forces, as opposed to being separated from the armed forces, may receive veterans' preference provided these individuals meet other applicable veterans' preference eligibility requirements; and (4) amended § 211.102(g) to correspond with the changes in § 211.102(a) and (b) by replacing the term ''Separated under honorable conditions'' with ''Discharged or released from active duty'' consistent with the statutory change contained in the Act.

OPM received written comments from one agency and 7 individuals, and one voice-mail comment from an individual. Of the nine comments received, three expressed concern and confusion as to whether dishonorably discharged veterans would receive veterans' preference under the new criteria. As stated in the interim regulation and § 211.102(g), a veteran must have been separated under honorable conditions (i.e., an honorable or general discharge) to be eligible for veterans' preference under these provisions.

One individual asked whether agencies must grant veterans' preference to employees currently on their rolls who did not have the preference documented at the time the interim regulation was published. Agencies are not required to update their employees' Official Personnel Files (OPF) as a result of the interim regulation. Because veterans' preference is a consideration in a reduction in force (RIF), any agency preparing for a RIF must update their employees' OPFs (block 26 on the Standard Form—50) to ensure that individuals entitled to veterans' preference are accorded their rights for RIF purposes.

One agency asked OPM to clarify the phrase, ''the date prescribed by Presidential proclamation or by law as the last day of Operation Iraqi Freedom'' contained in § 211.102(a)(6). The phrase refers to the ending date (yet to be determined) of the period during which anyone who served on active duty and is otherwise eligible is entitled to veterans' preference under these provisions. The President, through proclamation, or Congress, through legislation, is responsible for designating the termination date of military operations which qualify for veterans' preference. OPM will revise the regulations and update the VetGuide when this ending date becomes available.

Another commenter asked whether the expanded veterans' preference criteria in § 211.102(a)(6) is for purposes of granting 5-point veterans' preference or for some other purpose. Anyone who meets the criteria in § 211.102(a)(6), and is otherwise eligible, is entitled to 5-point veterans' preference as well as additional protection during a reduction in force. Otherwise eligible in this context means the veteran must meet the requirements of § 211.201(g) and have served either 24 months of continuous active duty, or the full period of time called or ordered to active duty. OPM is updating VetGuide to clarify this information.

One individual asked whether the veterans' preference criteria in § 211.102(a)(6) included veterans at the rank of major and above. The provision in § 211.102(a)(6) made no change to the statutory restriction against veterans' preference entitlement for retired officers at the rank of major and above. Therefore, military retirees at the rank of major, lieutenant commander, or higher are not eligible for preference in appointment unless they are disabled veterans (this restriction does not apply to reservists who will not begin drawing military retired pay until age 60).

One individual asked OPM to clarify whether a veteran must have served continuously for 24 months in order to be eligible under § 211.102(a)(6). A veteran must have served continuously for 24 months, or the full period called or ordered to active duty, in order to be eligible for veterans' preference under § 211.102(a)(6). This requirement, contained in 38 U.S.C. 5303A, prescribes a minimum of 2 years, service (or the full period called or ordered to active duty) for those enlisting after September 7, 1980, or who enter on active duty after October 14, 1982. This requirement does not apply to individuals seeking 10-point veterans' preference on the basis of a service-connected disability. OPM will

update VetGuide to further clarify the application of the 24-month requirement.

One commenter recommended OPM replace the word ''badge'' with ''medal'' or ''badge or medal'' in § 211.102(a)(2). OPM is not adopting this recommendation because the reference to ''badge'' is contained in law at 5 U.S.C. 2108(1)(A). Further, military personnel receive many awards and decorations which are determined by the Department of Defense. OPM and its predecessor agency, the Civil Service Commission, have always used the terms ''badge'' and ''medal'' interchangeably, as appropriate. We believe VetGuide provides sufficient explanation of the many badges and medals which qualify for purposes of veterans' preference.

The same individual asked OPM to clarify in the final regulation whether an Army ''service medal'' qualifies an individual for veterans' preference under part 211. OPM is not adopting this suggestion. The list of military campaigns, expeditions, awards, and decorations qualifying for veterans' preference is too lengthy to be contained in this part. However, OPM lists this information in Appendix A of VetGuide available on-line at *http://www.opm.gov/veterans/html/vgmedal2.asp.* In general, service medals are not qualifying for purposes of veterans' preference.

One commenter asked OPM to explain the significance of changing ''separated'' to ''released or discharged'' in § 211.102(a), (b), and (g). OPM modified part 211 in order to be consistent with recent statutory changes to 5 U.S.C. 2108. With these changes the law, OPM's implementing regulations, and Department of Defense (DD) Form 214, *Certificate of Release or Discharge from Active Duty*, the form used by veterans to claim 5-point veterans' preference, all use the same language which should make it easier for eligible veterans to receive their entitlement.

E.O. 12866, Regulatory Review

This rule has been reviewed by the Office of Management and Budget in accordance with Executive Order 12866.

Regulatory Flexibility Act

I certify that this regulation would not have a significant economic impact on a substantial number of small entities (including small businesses, small organizational units, and small governmental jurisdictions) because it affects only Federal agencies employees.

List of Subjects in 5 CFR Part 211

Government employees, Veterans.

Office of Personnel Management.

Linda M. Springer,

Director.

■ Accordingly, the interim rule amending part 211 of title 5, Code of Federal Regulations, which was published at 71 FR 33375 on June 9, 2006, is adopted as a final rule without changes.

[FR Doc. E7–4697 Filed 3–14–07; 8:45 am]

BILLING CODE 6325–39–P

OFFICE OF PERSONNEL MANAGEMENT

5 CFR PARTS 317, 353, 550, and 551

RIN 3206–AL21

Employment in the Senior Executive Service, Restoration To Duty From Uniformed Service or Compensable Injury, Pay Administration (General), and Pay Administration Under the Fair Labor Standards Act; Miscellaneous Changes to Pay and Leave Rules

AGENCY: Office of Personnel Management.

ACTION: Final rule.

SUMMARY: The Office of Personnel Management is issuing final regulations to amend a number of rules on pay and leave administration, including employment in the Senior Executive Service, use of paid leave during uniformed service, time limits for using compensatory time off earned in lieu of overtime pay, and other miscellaneous changes. The final regulations are being issued to standardize pay and leave policies in support of the consolidation of agency human resources and payroll systems.

DATES: The regulations are effective on May 14, 2007.

FOR FURTHER INFORMATION CONTACT: Sharon Dobson by telephone at (202) 606–2858; by fax at (202) 606–0824; or by e-mail at *pay-performance-policy@opm.gov.*

SUPPLEMENTARY INFORMATION: On January 5, 2005, the Office of Personnel Management (OPM) issued a comprehensive package of proposed regulations on Restoration to Duty From Uniformed Service or Compensable Injury; Payrates and Systems (General); Pay Under the General Schedule; Pay Administration (General); Pay Administration Under the Fair Labor Standards Act; Recruitment and Relocation Bonuses; Retention Allowances; Supervisory Differentials; Hours of Duty; and Absence and Leave (70 FR 1068). The proposed regulations are available at *http://www.opm.gov/fedregis.* The 60-day comment period ended on March 7, 2005. We received a total of 93 comments on the proposed regulations.

In these final regulations, we are addressing the revisions to rules concerning the retention of pay and benefits for a Senior Executive Service (SES) member who accepts a Presidential appointment, use of paid leave during uniformed service, time limits for using compensatory time off earned in lieu of overtime pay, and other miscellaneous rules. We have already published regulations for some of the subject areas included in the January 2005 proposed regulations in separate issuances in the **Federal Register**. Comments received on the proposed changes to the rules on Adjustments of Work Schedules for Religious Observances, Hours of Duty, and Absence and Leave will be addressed in subsequent issuances in the **Federal Register**.

Except as otherwise stated in this supplementary information, the purpose of the revisions in these final regulations is to standardize pay and leave policies in support of the consolidation of agency human resources and payroll systems and in general to aid agencies in the administration of these programs. All revisions are being made to regulations in title 5, Code of Federal Regulations.

Regulations Already Issued

Some of the changes included in the January 2005 proposed regulations have already been addressed in subsequent regulations issued by OPM on May 13, 2005, May 31, 2005, and August 17, 2006, as discussed below.

The January 2005 regulations proposed to amend the definition of rate of basic pay in §§ 575.103, 575.203, and 575.303 to clarify that night pay and environmental differential pay under the Federal Wage System are not included in the rate of basic pay for the purposes of recruitment, relocation, and retention incentives. The amended definition of rate of basic pay for the purpose of recruitment, relocation, and retention incentives was included in OPM's interim regulations issued on May 13, 2005, for recruitment, relocation, and retention incentives (70 FR 25732). The interim regulations are available at *http://www.opm.gov/fedregis.*

The January 2005 regulations proposed to add a new § 531.605 to define the requirements for determining an employee's official worksite for the purpose of identifying an employee's location-based pay entitlements, including locality rates and special

rates. The proposed regulations also addressed official worksite determinations for employees temporarily working at other locations and teleworking from an alternative worksite. The comments OPM received on proposed § 531.605 were addressed and changes made as an interim rule on May 31, 2005 (70 FR 31278). The interim regulations are available at *http://www.opm.gov/fedregis.* Section 531.605 was again revised in interim regulations issued on August 17, 2006, to clarify the rules for determining an employee's official worksite when he or she teleworks from an alternative worksite during an emergency situation, such as a pandemic health crisis (71 FR 47692). The interim regulations are available on OPM's Web site at *http://www.opm.gov/fedregis.*

Finally, the January 2005 regulations proposed to amend 5 CFR part 630, subpart D, concerning the use of sick leave for family care or bereavement purposes. The regulations proposed, among other changes, removing the requirement that a full-time employee must maintain 80 hours of sick leave in his or her sick leave account to use up to 104 hours (13 workdays) of his or her sick leave for general family care or bereavement purposes and up to 480 hours (12 workweeks) of sick leave to care for a family member with a serious health condition. The comments OPM received on the proposed amendments to 5 CFR part 630, subpart D, were addressed and changes made as a final rule on August 17, 2006 (71 FR 47693). The final regulations on sick leave are available at *http://www.opm.gov/fedregis.*

Final Regulations in This Issuance

In this issuance, the final regulations address the changes made to the rules on employment in the Senior Executive Service, use of paid leave during uniformed service, time limits for using compensatory time off earned in lieu of overtime pay, and other miscellaneous changes. For these subject areas, we received 29 comments on the January 2005 proposed regulations—20 from agencies, 6 from individuals, 2 from Federal labor unions, and 1 from a Federal employee association.

Senior Executive Service

Under 5 U.S.C. 5307(d), a higher aggregate limitation on pay (equal to the total annual compensation payable to the Vice President under 3 U.S.C. 104) applies to SES members in positions covered by a certified senior executive performance appraisal system. An agency questioned whether a former SES member may continue to retain the higher aggregate limitation on pay under the authority provided in 5 U.S.C. 3392(c) and § 317.801(b) to retain SES pay and benefits when he or she accepts a Presidential appointment. In these final regulations, we have amended § 317.801(b) to clarify that a former SES member who chooses to retain SES provisions related to basic pay, performance awards, awarding of ranks, severance pay, leave, and retirement may also choose to retain the higher aggregate limitation on pay that applied to the employee.

Paid Leave While Performing Uniformed Service

OPM proposed to amend § 353.208 to permit an employee, upon request, to use any accrued annual leave or military leave while performing service with the uniformed service, but not to use sick leave. An agency objected to the proposed change. The agency stated that the use of sick leave during a period of military service is a legitimate right of an employee under the provisions and intent of the Uniformed Services Employment and Reemployment Rights Act of 1994 (USERRA), (Public Law 103–353, October 13, 1994). We agree and are not adopting the proposed amendment. Section 353.208 will continue to permit an employee performing service in the uniformed service to use sick leave, when appropriate.

An agency recommended that OPM permit an employee to use compensatory time off earned in lieu of overtime pay and earned credit hours while performing uniformed service, since they both provide paid time off. We are not adopting this suggestion because employees are entitled to payment for unused compensatory time off and credit hours only in certain situations. We note that § 550.114(f)(2)(i) and § 551.531(f)(1) require agencies to provide payment for unused earned compensatory time off when an employee is separated or placed in a leave without pay status to perform uniformed service.

We believe it would be appropriate to allow an employee to use earned compensatory time off for travel under 5 CFR part 550, subpart N, while performing uniformed service because an employee may not receive payment for unused earned compensatory time off for travel. (See 5 U.S.C. 5550b(b) and § 550.1408.) We have revised § 353.208 to permit an employee to use earned compensatory time off for travel under 5 CFR part 550, subpart N, to perform uniformed service.

Section 1106 of the National Defense Authorization Act for Fiscal Year 2000 (Public Law 106–65, October 5, 1999) amended 5 U.S.C. 6323(a)(1) to permit an employee to use his or her entitlement to 15 days of military leave for "inactive duty training" (as defined in section 101 of title 37, United States Code) in addition to active duty and active duty training. Consistent with this statutory amendment, we proposed to delete the last sentence of § 353.208, which states an employee may not use military leave for inactive duty training. We did not receive any comments, and therefore, have deleted the last sentence in § 353.208 in these final regulations.

Time Limits for Using Earned Compensatory Time Off

The consolidation of human resources and payroll processing systems has revealed varying discretionary policies among agencies concerning time limits for using compensatory time off earned in lieu of overtime pay. These varying policies have resulted in increased costs for payroll providers to accommodate the myriad of agency policies within their systems and those increased costs are passed on to the agencies. As part of OPM's effort to support the consolidation of human resources and payroll processing systems, we proposed a standardized time limit of 26 pay periods for using compensatory time off earned in lieu of overtime pay that would be applied Governmentwide. The 26-pay period time limit would be applied to both employees not covered by the FLSA (FLS-exempt) under § 550.114 and employees covered by the FLSA (FLSA-nonexempt) under § 551.531. To assist in transitioning to the new time limitation, we proposed to provide an employee with unused compensatory time off to his or her credit on the effective date of the final regulations 26 pay periods after the effective date to use such compensatory time off.

In § 550.114(d), we proposed to provide agencies with discretionary authority to provide payment to FLSA-exempt employees for, or require forfeiture of, compensatory time off that is not used within the 26-pay period time limit. The proposed regulations at § 550.114(d)(2) allowed that if an FLSA-exempt employee is unable to take earned compensatory time off within 26 pay periods due to an exigency of the service beyond the employee's control, the agency must provide payment for the unused compensatory time off at the overtime rate in effect for the period during which the compensatory time off was earned. In addition, the proposed regulations at § 550.114(e)(2) (§ 550.114(f)(2) in the final regulations) required that if an FLSA-exempt

employee separates or goes on extended leave without pay to perform service in one of the uniformed services or because of an on-the-job injury with entitlement to injury compensation under 5 U.S.C. chapter 81, the agency must provide payment for the unused compensatory time off at the overtime rate in effect for the period during which the compensatory time off was earned.

In addition, to ensure consistent treatment of affected employees, OPM proposed amending § 551.531(d) to require an FLSA-nonexempt employee to use earned compensatory time off within 26 pay periods. An FLSA-nonexempt employee who fails to use earned compensatory time off earned within 26 pay periods or who separates or transfers from the agency before the earned compensatory time off is used, must be paid for the unused compensatory time off at the overtime rate in effect for the period during which the compensatory time off was earned. The proposed regulations at § 551.531(e) (§ 551.531(f) in the final regulations) also required that, if an FLSA-nonexempt employee is placed on leave without pay to perform service in the uniformed services or because of an on-the-job injury with entitlement to injury compensation under 5 U.S.C. chapter 81, the agency must provide payment for the unused compensatory time off at the overtime rate in effect for the period during which the compensatory time off was earned.

One agency recommended a shorter time limitation—*e.g.*, 13 pay periods—for using compensatory time off earned in lieu of overtime pay. An individual opposed the limitation of 26 pay periods. The two labor organizations opposed providing agencies with discretionary authority to determine whether an FLSA-exempt employee must forfeit or receive payment for unused compensatory time off. One labor organization recommended expanding the circumstances in which an employee must receive payment for unused compensatory time off to include reduction in force (RIF) situations. The other labor organization believed FLSA-exempt employees should receive payment for compensatory time off not used within 26 pay periods or be given additional time to use the compensatory time off.

We disagree with these recommendations. Unlike FLSA-nonexempt employees, who have a statutory entitlement to receive payment for unused compensatory time off, FLSA-exempt employees do not have any such statutory entitlement. Legislation is needed to provide FLSA-exempt employees with an entitlement to receive payment for unused compensatory time off. In addition, requiring agencies to provide payment for unused compensatory time off to FLSA-exempt employees would significantly increase costs for Federal agencies. Finally, we believe 26 pay periods is sufficient time for most employees to use their earned compensatory time off. We note that § 550.114(d)(2) requires agencies to provide payment for compensatory time off if an employee's failure to use his or her earned compensatory time off is due to an exigency of the service beyond the employee's control.

An agency was concerned that a "rolling" 26-pay period time limit would be an administrative burden for agencies to track. Another agency suggested using a fixed yearly date for employees to use earned compensatory time off because it would provide for easier tracking and monitoring. We are not adopting these suggestions. We believe most agencies already impose on employees a "rolling" time limit for using earned compensatory time off. Therefore, the proposed regulations would not impose an additional administrative burden on the agencies. A fixed yearly date for using earned compensatory time off would result in providing varying lengths of time for individual employees to use earned compensatory time off, depending on when the employee earned the compensatory time off. We believe imposing a time limit of 26 pay periods within which to use earned compensatory time off results in fair and equitable treatment of affected employees and supports our goal of standardizing pay policies. Employees will all have the same number of pay periods within which they must use their earned compensatory time off. We are adopting the revised regulations in § 550.114(d) and (f) and § 551.531(f) as final.

Two agencies disagreed with proposed § 550.114(d), which would give an employee with unused compensatory time off to his or her credit as of the effective date of the final regulations 26 pay periods after the effective date of the final regulations to use the compensatory time off. One agency suggested providing agencies with discretionary authority to extend the time limitation for using earned compensatory time off for employees who have been unable to use earned compensatory time off prior to the effective date of the final regulations because of work requirements or scheduling conflicts. Another agency is concerned that the proposed rule would have major budgetary implications if the agency's policy were to provide payment for unused compensatory time off and employees are unable to use their earned compensatory time off within 26 pay periods after the effective date of the final regulations. The agency suggested that employees who have compensatory time off to their credit as of the effective date of the final regulations be given a minimum of 3 years to use the compensatory time off. We agree and have added a new paragraph (e) to § 550.114 and § 551.531 of the final regulations to allow an employee who has compensatory time off to his or her credit as of the effective date of the final regulations at least 3 years to use the earned compensatory time off.

One agency suggested revising the proposed regulations to require an employee to use earned compensatory time off within 26 pay periods after the pay period during which it was earned. The agency suggested beginning the 26-pay period time limit after the pay period during which it was earned will ensure standardized recordkeeping and tracking. We agree and have revised § 550.114(d) and § 551.531(d) to require that compensatory time off that is not used within 26 pay periods after the pay period during which it was earned must be paid by the agency or forfeited by the employee.

An agency noted that proposed § 550.114(e)(1) addresses the treatment of compensatory time off when an employee either transfers or separates from an agency, while § 551.531(d) addresses the treatment of compensatory time off only when an employee separates from an agency. To remedy this, we have revised § 551.531(d) to address the treatment of compensatory time off when an employee transfers to a different agency.

Finally, we are redesignating § 551.531(e) as § 551.531(g), and correcting new paragraph (g) by deleting language that states the value of compensatory time off for FLSA-nonexempt employees is considered in applying pay limitations. Compensatory time off for FLSA-nonexempt employees should not be considered in applying the biweekly or annual premium pay limitations established under 5 U.S.C. 5547 or the aggregate limitation on pay established under 5 U.S.C. 5307. In addition, we are correcting a citation in §§ 550.112(j)(1) and 551.422(d) from "(41 CFR 301–1.3(c)(4))" to "(41 CFR 300–3.1)," which references the definition of *official station* in the General Services Administration's Federal Travel Regulations.

An individual requested clarification of the terms *irregular or occasional overtime work* in relationship to earning compensatory time off. As defined in § 550.103, *irregular or occasional overtime work* means overtime work that is not part of an employee's regularly scheduled administrative workweek (*i.e.*, the period within an administrative workweek in which an employee is regularly scheduled to work).

Other Miscellaneous Changes

Lump-Sum Payments for Annual Leave

The regulations governing lump-sum payments for accumulated and accrued annual leave for employees who separate from Federal service in 5 CFR 550, subpart L, have been revised to ensure consistency with the guidance provided in the OPM Operating Manual on the Federal Wage System. The revised regulations ensure that a lump-sum payment for employees who work a regular rotating schedule involving work on both day and night shifts is calculated as if the employee had continued to work beyond the effective date of separation. An agency asked that we clarify what is meant by ''work beyond the effective date of separation.'' Another agency requested clarification in determining whether a lump-sum payment should be extended to the end of an employee's last scheduled shift. Under 5 U.S.C. 5551, a lump-sum payment must equal the pay an employee would have received had he or she remained in Federal service until expiration of the period of annual leave. Agencies must project a lump-sum period to include any accumulated and accrued annual leave to the employee's credit, as of the date of separation. The lump-sum leave period is the employee's annual leave projected forward for all workdays the employee would have worked if he or she had remained in Federal service, including holidays (even though they are typically nonworkdays) as required by 5 U.S.C. 5551(a), until the expiration of the employee's accumulated and accrued annual leave. The final regulations in § 550.1205(b)(5) state that a night differential is payable for that portion of the lump-sum period that would have occurred when the employee was scheduled to work night shifts. The lump-sum period extends only through the last hour of annual leave.

Restriction on Paying Sunday Premium Pay

Section 636 of the Treasury and General Government Appropriations Act, 1998 (Public Law 105–61, October 10, 1997), permanently restricted the payment of Sunday premium pay for all employees Governmentwide who are paid from appropriated funds and who do not actually perform work on Sunday. Section 624 of the Treasury and General Government Appropriations Act, 1999 (Public Law 105–277, October 21, 1998), expanded the permanent restriction on the payment of Sunday premium pay to cover employees who are paid from any Act (including payments from revolving funds). These provisions effectively prohibit the payment of Sunday premium pay to employees during any period when no work is performed. This includes holidays, periods of paid leave, excused absence (administrative leave), compensatory time off, credit hours, or time off as an incentive or performance award. The restriction covers employees who are paid from any Act, including payments from revolving funds. Consistent with this permanent legal restriction, we have revised § 550.171(a) by deleting language stating that Sunday premium pay is paid during periods of paid leave or excused absence. We also will revise our guidance on payment of Sunday premium pay during periods of paid leave in the OPM Operating Manual for the Federal Wage System.

E.O. 12866, Regulatory Review

This rule has been reviewed by the Office of Management and Budget in accordance with E.O. 12866.

Regulatory Flexibility Act

I certify that these regulations would not have a significant economic impact on a substantial number of small entities because they would apply only to Federal agencies and employees.

List of Subjects in 5 CFR Parts 317, 353, 550, and 551

Administrative practice and procedure, Claims, Government employees, Law enforcement officers, Reporting and recordkeeping requirements, Wages.

Office of Personnel Management.

Linda M. Springer,

Director.

■ Accordingly, OPM amends parts 317, 353, 550, and 551 of title 5 of the Code of Federal Regulations to read as follows:

PART 317—EMPLOYMENT IN THE SENIOR EXECUTIVE SERVICE

■ 1. The authority citation for part 317 continues to read as follows:

Authority: 5 U.S.C. 3392, 3393, 3395, 3397, 3592, 3593, 3595, 3596, 8414, and 8421.

Subpart H—Retention of SES Provisions

■ 2. In § 317.801, paragraph (b)(1) is revised to read as follows:

* * * * *

(b) *Election.* (1) At the time of appointment, an appointee covered by paragraph (a) of this section may elect to retain some, all, or none of the following SES provisions related to basic pay (including the aggregate limitation on pay established by 5 U.S.C. 5307), performance awards, awarding of ranks, severance pay, leave, and retirement. That election will remain in effect for no less than 1 year, unless the appointee leaves the position sooner.

* * * * *

PART 353—RESTORATION TO DUTY FROM UNIFORMED SERVICE OR COMPENSABLE INJURY

■ 3. The authority citation for part 353 continues to read as follows:

Authority: 38 U.S.C. 4301 et. seq., and 5 U.S.C. 8151

Subpart B—Uniformed Service

■ 4. Section 353.208 is revised to read as follows:

§ 353.208 Use of paid leave during uniformed service.

An employee performing service with the uniformed services must be permitted, upon request, to use any accrued annual leave under 5 U.S.C. 6304, military leave under 5 U.S.C. 6323, or earned compensatory time off for travel under 5 U.S.C. 5550b during such service.

PART 550—PAY ADMINISTRATION (GENERAL)

Subpart A—Premium Pay

■ 5. The authority citation for subpart A continues to read as follows:

Authority: 5 U.S.C. 5304 note, 5305 note, 5504(d), 5541(2)(iv), 5545a(h)(2)(B) and (i), 5547(b) and (c), 5548, and 6101(c); sections 407 and 2316, Pub. L. 105–277, 112 Stat. 2681–101 and 2681–828 (5 U.S.C. 5545a); E.O. 12748, 3 CFR, 1992 Comp., p. 316.

§ 550.112 [Amended]

■ 6. In § 550.112(j)(1), remove the citation ''(41 CFR 301–1.3(c)(4))'' and add in its place ''(41 CFR 300–3.1).''

■ 7. In § 550.114, paragraph (d) is revised, paragraph (e) is redesignated as paragraph (g), and new paragraphs (e) and (f) are added to read as follows:

§ 550.114 Compensatory time off.

* * * * *

(d) Except as provided in paragraph (f)(2) of this section, an employee must use accrued compensatory time off to which he or she is entitled under paragraph (a) or (b) of this section by the end of the 26th pay period after the pay period during which it was earned. The head of an agency, at his or her sole and exclusive discretion, may provide that an employee who fails to take compensatory time off to which he or she is entitled within 26 pay periods after the pay period during which it was earned must—

(1) Receive payment for such unused compensatory time off at the dollar value prescribed in paragraph (g) of this section; or

(2) Forfeit the unused compensatory time off, unless the failure to take the compensatory time off is due to an exigency of the service beyond the employee's control, in which case the agency head must provide payment for the unused compensatory time off at the dollar value prescribed in paragraph (g) of this section.

(e) Except as provided in paragraph (f)(2) of this section, compensatory time off to an employee's credit as of May 14, 2007 must be used by the end of the pay period ending 3 years after May 14, 2007. The head of an agency, at his or her sole and exclusive discretion, may provide that an employee who fails to take compensatory time off to which he or she is entitled by the end of the pay period ending 3 years after May 14, 2007 must—

(1) Receive payment for such unused compensatory time off at the dollar value prescribed in paragraph (g) of this section; or

(2) Forfeit the unused compensatory time off, unless the failure to take the compensatory time off is due to an exigency of the service beyond the employee's control, in which case the agency head must provide payment for the unused compensatory time off at the dollar value prescribed in paragraph (g) of this section.

(f)(1) Except as provided in paragraph (f)(2) of this section, an employee with unused compensatory time off under paragraph (a) or (b) of this section who transfers to another agency or separates from Federal service before the expiration of the time limit established under paragraphs (d) or (e) of this section may receive overtime pay or forfeit the unused compensatory time off, consistent with the employing agency's policy established under paragraphs (d) and (e) of this section.

(2) If an employee with unused compensatory time off under paragraph (a) or (b) of this section separates from Federal service or is placed in a leave without pay status under the following circumstances, the employee must be paid for unused compensatory time off at the dollar value prescribed in paragraph (g) of this section:

(i) The employee separates or is placed in a leave without pay status to perform service in the uniformed services (as defined in 38 U.S.C. 4303 and § 353.102); or

(ii) The employee separates or is placed in a leave without pay status because of an on-the-job injury with entitlement to injury compensation under 5 U.S.C. chapter 81.

* * * * *

■ 8. In § 550.171, paragraph (a) is revised to read as follows:

§ 550.171 Authorization of pay for Sunday work.

(a) A full-time employee is entitled to pay at his or her rate of basic pay plus premium pay at a rate equal to 25 percent of his or her rate of basic pay for each hour of Sunday work (as defined in § 550.103).

* * * * *

Subpart L—Lump-Sum Payment for Accumulated and Accrued Annual Leave

■ 9. The authority citation for subpart L continues to read as follows:

Authority: 5 U.S.C. 5553, 6306, and 6311.

■ 10. In § 550.1205, revise paragraph (b)(5)(i) and paragraph (g) to read as follows:

§ 550.1205. Calculating a lump-sum payment.

* * * * *

(b) * * *

(5) * * *

(i) Night differential under 5 U.S.C. 5343(f) at the applicable percentage rate received by a prevailing rate employee for all regularly scheduled periods of night shift duty covered by the unused annual leave as if the employee had continued to work beyond the effective date of separation, death, or transfer. In the case of an employee who is assigned to a regular rotating schedule involving work on both day and night shifts, the night differential is payable for that portion of the lump-sum period that would have occurred when the employee was scheduled to work night shifts.

* * * * *

(g) For a reemployed annuitant who becomes eligible for a lump-sum payment under § 550.1203, the agency must compute the lump-sum payment using the annuitant's pay before any reductions required under § 837.303 of this chapter.

* * * * *

PART 551—PAY ADMINISTRATION UNDER THE FAIR LABOR STANDARDS ACT

■ 11. The authority citation for part 551 continues to read as follows:

Authority: 5 U.S.C. 5542(c); Sec. 4(f) of the Fair Labor Standards Act of 1938, as amended by Pub. L. 93–259, 88 Stat. 55 (29 U.S.C. 204f).

Subpart D—Hours of Work

§ 551.422 [Amended]

■ 12. In § 551.422(d), remove the citation ''(41 CFR 301–1.3(c)(4))'' and add in its place ''(41 CFR 300–3.1).''

Subpart E—Overtime Pay Provisions

■ 13. In § 551.531, paragraph (d) is revised, paragraph (e) is revised and redesignated as paragraph (g), and new paragraphs (e) and (f) are added to read as follows:

§ 551.531 Compensatory time off.

* * * * *

(d) If compensatory time off earned under paragraph (a) or (b) of this section is not taken within 26 pay periods after the pay period during which it was earned or if the employee transfers or separates from an agency before using the compensatory time, the employee must be paid for overtime work at the dollar value prescribed in paragraph (g) of this section.

(e) Compensatory time off to an employee's credit as of May 14, 2007 must be used by the end of the pay period ending 3 years after May 14, 2007. If the earned compensatory time off is not taken by the end of the pay period ending 3 years after May 14, 2007, the employee must be paid for overtime work at the dollar value prescribed in paragraph (g) of this section.

(f) If an employee with unused compensatory time off under paragraphs (a), (b), or (e) of this section separates from Federal service or is placed in a leave without pay status under the following circumstances, the employee must be paid for overtime work at the overtime rate at the dollar value prescribed in paragraph (g) of this section:

(1) The employee is separated or placed in a leave without pay status to perform service in the uniformed services (as defined in 38 U.S.C. 4303 and § 353.102); or

(2) The employee is separated or placed in a leave without pay status because of an on-the-job injury with entitlement to injury compensation under 5 U.S.C. chapter 81.

(g) The dollar value of compensatory time off when it is liquidated is the amount of overtime pay the employee otherwise would have received for hours of the pay period during which compensatory time off was earned by performing overtime work.

* * * * *

[FR Doc. E7–4696 Filed 3–14–07; 8:45 am]

BILLING CODE 6325–39–P

OFFICE OF PERSONNEL MANAGEMENT

5 CFR Part 875

RIN 3206–AK99

Federal Long Term Care Insurance Program: Miscellaneous Changes, Corrections, and Clarifications

AGENCY: Office of Personnel Management.

ACTION: Final regulation.

SUMMARY: The Office of Personnel Management (OPM) is issuing a final rule to make miscellaneous changes, corrections, and clarifications to the Federal Long Term Care Insurance Program (FLTCIP) regulations.

DATES: *Effective Date:* April 16, 2007.

FOR FURTHER INFORMATION CONTACT: Edward M. DeHarde, Center for Employee and Family Support Policy, Strategic Human Resources Policy Division, Office of Personnel Management, 1900 E Street, NW., Washington, DC 20415; or call him at 202–606–0004.

SUPPLEMENTARY INFORMATION: The current FLTCIP regulations were published in the **Federal Register** at 70 FR 30605, May 27, 2005. In those regulations OPM replaced references to ''Federal civilian and Postal employees and members of the uniformed services'' with ''active workforce member'' in several places. We are making a similar change in two additional places: § 875.405 and § 875.410. We are also correcting a section reference in § 875.209 of the previously published regulations.

In addition, § 875.408 of the FLTCIP regulations discusses incontestability, a provision that allows coverage based on an erroneous application to continue under certain circumstances. The FLTCIP contractor often doesn't learn that coverage is based on an erroneous application until someone files a claim, and the contractor becomes aware that the information on the individual's application differed from what is shown in the individual's medical records. If the erroneous coverage has been in effect less than two years, or if the application contained knowingly false or misleading information, the contractor may rescind (void) the coverage and refund the individual's premiums. Section 875.104 of the FLTCIP regulations contains procedures for resolving disputes concerning eligibility for benefits and payment of claims. These final regulations clarify that the claims dispute procedures apply only to persons who have valid coverage under the Program. They do not apply to individuals whose erroneous coverage is rescinded.

A proposed rule was published to amend 5 CFR part 875 in the **Federal Register** at 71 FR 19459, April 14, 2006. OPM requested comments by June 13, 2006. We received one comment by that date, from an FLTCIP enrollee. The issues raised by this commenter are discussed below.

The commenter did not address the miscellaneous changes, corrections, and clarifications that were contained in the proposed regulation. Instead, the commenter suggested that OPM should specifically list in the regulations which injuries qualify for coverage under FLTCIP to ensure that enrollees with similar injuries receive similar coverage. The comment received is beyond the scope of the proposed change to FLTCIP regulations. In addition, coverage under FLTCIP is not based on an enrollee's injury or medical diagnosis; it is based on an enrollee's established inability to perform defined activities of daily living or an enrollee's severe cognitive impairment. Therefore, for the reasons supplied in the proposed rule, the proposed rule amending 5 CFR part 875 which was published in the **Federal Register** at 71 FR 19459, April 14, 2006, is adopted as a final rule without change.

Executive Order 12866, Regulatory Review

This rule has been reviewed by the Office of Management and Budget in accordance with Executive Order 12866.

Regulatory Flexibility Act

I certify that these regulations will not have a significant economic impact on a substantial number of small entities because they affect only enrollees in the Federal Long Term Care Insurance Program.

List of Subjects in 5 CFR Part 875

Administrative practices and procedures, Employee benefit plans, Government contracts, Government employees, Health insurance, Military personnel, Retirement.

Office of Personnel Management.

Linda M. Springer,

Director.

■ Accordingly, OPM is amending 5 CFR part 875, as follows:

PART 875—FEDERAL LONG TERM CARE INSURANCE PROGRAM

■ 1. The authority citation for 5 CFR part 875 continues to read as follows:

Authority: Authority: 5 U.S.C. 9008.

■ 2. In § 875.104 add paragraph (f) to read as follows:

§ 875.104 What are the steps required to resolve a dispute involving benefit eligibility or payment of a claim?

* * * * *

(f) The procedures described in paragraphs (a), (b), (c), (d), and (e) of this section apply only if you have valid coverage under the FLTCIP. If the Carrier determines that your coverage was based on an erroneous application and voids the coverage as described in § 875.408 of this part, these provisions do not apply. The Carrier will provide you with information on your review rights in its rescission letter (letter voiding your coverage).

■ 3. In § 875.209 revise the last sentence of paragraph (b) to read as follows:

§ 875.209 How do I demonstrate that I am eligible to apply for coverage?

* * * * *

(b) * * * The incontestability provisions in § 875.408 do not apply to this section.

■ 4. In § 875.405 revise the first sentence of paragraph (a)(1) to read as follows:

§ 875.405 If I marry, may my new spouse apply for coverage?

(a)(1) If you are an active workforce member and you have married, your spouse is eligible to submit an application for coverage under this section within 60 days from the date of your marriage and will be subject to the underwriting requirements in force for the spouses of active workforce members during the most recent open season. * * *

* * * * *

■ 5. In § 875.408 revise paragraph (a) to read as follows:

§ 875.408 What is the significance of incontestability?

(a) Incontestability means coverage issued based on an erroneous application may remain in effect. Such coverage will not remain in effect under any of the following conditions:

(1) If your coverage has been in force for less than 6 months, the Carrier may void your coverage upon a showing that information on your signed application that was material to your approval for coverage is different from what is shown in your medical records.

(2) If your coverage has been in force for at least 6 months but less than 2 years, the Carrier may void your coverage upon a showing that information on your signed application that was material to your approval for coverage is different from what is shown in your medical records and pertains to the condition for which benefits are sought.

(3) After your coverage has been in effect for 2 years, the Carrier may void your coverage only upon a showing that you knowingly and intentionally made a false or misleading statement or omitted information in your signed application for coverage regarding your health status that was material to your approval for coverage.

(4) If your coverage is voided, as described in paragraph (a)(1), (a)(2), or (a)(3) of this section, no claims will be paid. In addition, the provisions of § 875.104 relating to the procedures for resolving a dispute involving benefits eligibility or claims denials do not apply to your situation. You may request a review by the Carrier if you believe that your coverage was voided in error. You must submit your request in writing to the Carrier within 30 days of the date of the rescission letter (letter voiding your coverage).

* * * * *

■ 6. In § 875.410 revise the first sentence to read as follows:

§ 875.410 May I continue my coverage when I leave Federal or military service?

If you are an active workforce member, your coverage will automatically continue when you leave active service, as long as the Carrier continues to receive the required premium when due. * * *

[FR Doc. E7–4695 Filed 3–14–07; 8:45 am]

BILLING CODE 6325–39–P

DEPARTMENT OF AGRICULTURE

Agricultural Marketing Service

7 CFR Parts 916 and 917

[Docket No. AMS–FV–06–0190; FV07–916/917–2 FIR]

Nectarines and Peaches Grown in California; Temporary Suspension of Provisions Regarding Continuance Referenda Under the Nectarine and Peach Marketing Orders

AGENCY: Agricultural Marketing Service, USDA.

ACTION: Final rule.

SUMMARY: The Department of Agriculture (USDA) is adopting, as a final rule, without change, an interim final rule temporarily suspending order provisions that require continuance referenda to be conducted for the nectarine and peach marketing orders during winter 2006–07. This rule enables USDA to postpone conducting the continuance referenda until the industry has had sufficient time to evaluate the effects of recent amendments to the marketing orders. Temporary suspension of the continuance referenda should also minimize confusion during the current committee nomination period, which overlaps with the scheduled referenda period.

DATES: *Effective Date:* April 16, 2007.

FOR FURTHER INFORMATION CONTACT: Laurel May, Marketing Order Administration Branch, Fruit and Vegetable Programs, AMS, USDA, 1400 Independence Avenue SW, STOP 0237, Washington, DC 20250–0237; *Telephone:* (202) 720–2491, *Fax:* (202) 720–8938, or *E-mail*: *Laurel.May@usda.gov*; or Kurt Kimmel, Regional Manager, California Marketing Field Office, Marketing Order Administration Branch, Fruit and Vegetable Programs, AMS, USDA, 2202 Monterey Street, Suite 102B, Fresno, California 93721; *Telephone:* (559) 487–5901, *Fax:* (559) 487–5906, or *E-mail*: *Kurt.Kimmel@usda.gov.* The rule can be viewed at *http://www.regulations.gov.*

Small businesses may request information on complying with this regulation by contacting Jay Guerber, Marketing Order Administration Branch, Fruit and Vegetable Programs, AMS, USDA, 1400 Independence Avenue SW., Stop 0237, Washington, DC 20250–0237; *Telephone:* (202) 720–2491, *Fax:* (202) 720–8938, or *E-mail*: *Jay.Guerber@usda.gov.*

SUPPLEMENTARY INFORMATION: This rule is issued under Marketing Order Nos. 916 and 917, both as amended (7 CFR parts 916 and 917), regulating the handling of nectarines and peaches grown in California, respectively, hereinafter referred to as the ''orders.'' The orders are effective under the Agricultural Marketing Agreement Act of 1937, as amended (7 U.S.C. 601–674), hereinafter referred to as the ''Act.''

USDA is issuing this rule in conformance with Executive Order 12866.

This rule has been reviewed under Executive Order 12988, Civil Justice Reform. This rule is not intended to have retroactive effect. This rule will not preempt any State or local laws, regulations, or policies, unless they present an irreconcilable conflict with this rule.

The Act provides that administrative proceedings must be exhausted before parties may file suit in court. Under section 608c(15)(A) of the Act, any handler subject to an order may file with USDA a petition stating that the order, any provision of the order, or any obligation imposed in connection with the order is not in accordance with law and request a modification of the order or to be exempted therefrom. A handler is afforded the opportunity for a hearing on the petition. After the hearing, USDA would rule on the petition. The Act provides that the district court of the United States in any district in which the handler is an inhabitant, or has his or her principal place of business, has jurisdiction to review USDA's ruling on the petition, provided an action is filed not later than 20 days after date of the entry of the ruling.

This rule continues in effect the action that temporarily suspends the provisions in §§ 916.64(e) and 917.61(e) of the orders, which specify when continuance referenda should be conducted to determine whether growers favor continuance of the orders. Temporary suspension of the provisions for continuance referenda will provide growers with more time to evaluate the effects of recent amendments to the orders before voting on continuance of the marketing programs. Suspension of the referenda requirements will also diminish the confusion likely to occur if the referenda are held during current committee nominations. These actions were unanimously recommended by the Nectarine Administrative Committee (NAC) and the Peach Commodity Committee (PCC) (committees) at their August 31, 2006, meetings.

Nectarines

Section 916.64(e) of the nectarine marking order currently provides that USDA shall conduct a continuance

referendum between December 1 and February 15 of every fourth fiscal period since winter 1974–75 to ascertain whether continuance of the order is favored by nectarine growers. A continuance referendum is, therefore, scheduled to be conducted between December 1, 2006, and February 15, 2007. Authorization to suspend the continuance referendum requirement is provided in § 916.64(b).

The NAC recommended that the provision requiring the winter 2006–07 continuance referendum be temporarily suspended to allow the industry time to fully realize the impact of recent amendments to the marketing order. Amendments to the order were approved by nectarine growers in a referendum held in March 2006. The majority of the amendments were implemented on January 1, 2007. The continuance referendum cycle will resume as provided in § 916.64(e) in the period between December 1, 2010, and February 15, 2011. A referendum can be held in the interim if deemed appropriate by USDA.

Among the recent amendments to the order are revisions to the NAC's nomination procedures, which require a transition to mail balloting. Ballots for the 2007–09 term of office were mailed to growers in January 2007. The NAC believes that receiving both the nomination ballots and the continuance referenda ballots during this transitional period would confuse growers, who would then be less likely to return any of the ballots. The committees expect that temporary suspension of the continuance referendum will minimize confusion and maximize grower participation in both the committee nominations and the continuance referendum. After this initial transitional period, biennial committee nominations should take place earlier in the year and are not expected to overlap with scheduled continuance referendum periods.

Peaches

Section 917.61(e) of the peach marketing order currently provides that USDA shall conduct a continuance referendum between December 1 and February 15 of every fourth fiscal period since winter 1974–75 to ascertain whether continuance of the order is favored by peach growers. A continuance referendum is, therefore, scheduled to be conducted between December 1, 2006 and February 15, 2007. Authorization to suspend the continuance referendum requirement is provided in § 917.61(b).

The PCC recommended that the provision requiring the winter 2006–07 continuance referendum be temporarily suspended to allow the industry time to fully realize the impact of recent amendments to the marketing order. Amendments to the order were approved by peach growers in a referendum held in March 2006. The majority of the amendments were implemented on January 1, 2007. The continuance referendum cycle will resume as provided in § 917.61(e) in the period between December 1, 2010, and February 15, 2011. A referendum can be held in the interim if deemed appropriate by USDA.

Section 917.61(e) also requires that USDA conduct continuance referenda regarding the provisions of Part 917 pertaining to pears. Although the provisions pertaining to pears are currently suspended, the pear referenda are conducted concurrently with the peach and nectarine continuance referenda. In order to stay synchronized with the peach and nectarine referenda, the pear referendum will not be held during the period between December 1, 2006, and February 15, 2007. The pear continuance referendum cycle will resume as provided in § 917.61(e) in the period between December 1, 2010, and February 15, 2011. A referendum can be held in the interim if deemed appropriate by USDA.

Among the recent amendments to the order are revisions to the PCC's nomination procedures, which require a transition to mail balloting. Ballots for the 2007–09 term of office were mailed to growers in January 2007. The PCC believes that receiving both the nomination ballots and the continuance referenda ballots during this transitional period would confuse growers, who would then be less likely to return any of the ballots. The committees expect that temporary suspension of the continuance referendum will minimize confusion and maximize grower participation in both the committee nominations and the continuance referendum. After this initial transitional period, biennial committee nominations should take place earlier in the year and are not expected to overlap with scheduled continuance referendum periods.

Final Regulatory Flexibility Act

Pursuant to requirements set forth in the Regulatory Flexibility Act (RFA), the Agricultural Marketing Service (AMS) has considered the economic impact of this action on small entities. Accordingly, AMS has prepared this final regulatory flexibility analysis.

The purpose of the RFA is to fit regulatory actions to the scale of business subject to such actions in order that small businesses will not be unduly or disproportionately burdened. Marketing orders issued pursuant to the Act, and the rules issued thereunder, are unique in that they are brought about through group action of essentially small entities acting on their own behalf. Thus, both statutes have small entity orientation and compatibility.

There are approximately 150 handlers of nectarines and peaches who are subject to regulation under the order and approximately 800 growers of these fruits in the regulated area. Small agricultural service firms, which include handlers, have been defined by the Small Business Administration (13 CFR 121.201) as those having annual receipts of less than $6,500,000, and small agricultural growers are defined as those having annual receipts of less than $750,000. The majority of California nectarine and peach handlers and growers may be classified as small entities.

The committees' staff has estimated that there are fewer than 26 handlers in the industry who could be defined as other than small entities. For the 2005 season, the committees' staff estimated that the average handler price received was $10.00 per container or container equivalent of nectarines or peaches. A handler would have to ship at least 600,000 containers to have annual receipts of $6,000,000. Given data on shipments maintained by the committees' staff and the average handler price received during the 2005 season, the committees' staff estimates that small handlers represent approximately 86 percent of all the handlers within the industry.

The committees' staff has also estimated that fewer than 10 percent of the growers in the industry could be defined as other than small entities. For the 2005 season, the committees' staff estimated the average grower price received was $5.25 per container or container equivalent for nectarines and peaches. A grower would have to produce at least 142,858 containers of nectarines and peaches to have annual receipts of $750,000. Given data maintained by the committees' staff and the average grower price received during the 2005 season, the committees' staff estimates that small growers represent more than 90 percent of the producers within the industry.

With an average grower price of $5.25 per container or container equivalent, and a combined packout of nectarines and peaches of approximately 38,776,500 containers, the value of the 2005 packout is estimated to be $203,576,600. Dividing this total estimated grower revenue figure by the

estimated number of growers (800) yields an estimated average revenue per grower of about $254,471 from the sales of peaches and nectarines.

This rule continues in effect the action that temporarily suspends the provisions in §§ 916.64(e) and 917.61(e), which specify the time period in which continuance referenda should be conducted to determine if growers favor continuance of the nectarine and peach marketing orders, respectively. Pursuant to these provisions, the next continuance referenda are scheduled for the period between December 1, 2006, and February 15, 2007. Authorization to suspend these provisions is provided in §§ 916.64(b) and 917.61(b) of the orders.

The committees recommended suspension of these provisions to allow the industry time to evaluate the effects of recent amendments to the marketing orders before voting on continuation of the programs. For instance, several of the amendments were intended to increase industry participation in program activities. Others were intended to modernize the marketing orders' operations to better reflect current industry business practices. Postponing the referenda will give the industry time to operate under the amended orders and determine whether the intended goals were met before the next continuance referenda. The continuance referenda cycles as provided in §§ 916.64(e) and 917.61(e) will resume in the period between December 1, 2010, and February 15, 2011. Referenda can be held in the interim if deemed appropriate by USDA.

This action is also expected to decrease the confusion likely to occur if the continuance referenda scheduled for the period between December 1, 2006, and February 15, 2007, are held as scheduled. Implementation of the order amendments required a transition to mail balloting for NAC and PCC nominations in January 2007, which would overlap with the scheduled continuance referenda. Growers could each receive as many as four ballots during the overlapping nominations and referenda periods if they produce both nectarines and peaches. The committees are concerned that the flood of ballots could confuse growers and discourage them from participating fully. Therefore, the committees recommended that the continuance referenda be postponed. After this initial transitional period the biennial committee nominations should take place earlier in the year and are not expected to overlap with scheduled continuance referenda periods.

One alternative to this action would be to conduct the referenda as scheduled. However, the committees believe that growers need additional time to evaluate the effectiveness of the amendments that were adopted before voting on continuation of the marketing programs. Postponing the continuance referenda until a later time is expected to provide a better assessment of industry support for the orders. Further, if the continuance referenda were not postponed the referenda period would overlap with the committee nominations period. Voter confusion would likely occur due to the receipt of multiple ballots during that time. The committees were concerned that the confusion would lead to decreased grower participation in both the referenda and the committee nominations. Therefore, USDA has determined that the provisions requiring that continuance referenda be conducted during the period between December 1, 2006, and February 15, 2007, should be temporarily suspended.

The AMS is committed to complying with the E-Government Act, to promote the use of the Internet and other information technologies to provide increased opportunities for citizen access to Government information and services, and for other purposes.

This rule will not impose any additional reporting or recordkeeping requirements on either small or large nectarine or peach handlers. As with all Federal marketing order programs, reports and forms are periodically reviewed to reduce information requirements and duplication by industry and public sector agencies.

In addition, USDA has not identified any relevant Federal rules that duplicate, overlap, or conflict with this rule.

Further, the committees' meetings were widely publicized throughout the nectarine and peach industry and all interested persons were invited to attend the meetings and participate in committee deliberations. Like all committee meetings, the August 31, 2006, meetings were public meetings and all entities, both large and small, were able to express their views on this issue.

An interim final rule concerning this action was published in the **Federal Register** on December 28, 2006. The committees posted the rule on their Web site. In addition, the rule was made available through the Internet by USDA and the Office of the Federal Register. That rule provided for a 30-day comment period which ended January 29, 2007. One comment supporting the proposal was received. The commenter cited more time to evaluate the effects of recent amendments to the order and reduced confusion for committee nominations as justification for temporarily suspending the provisions for continuance referenda.

A small business guide on complying with fruit, vegetable, and specialty crop marketing agreements and orders may be viewed at: *http://www.ams.usda.gov/fv/moab.html.* Any questions about the compliance guide should be sent to Jay Guerber at the previously mentioned address in the **FOR FURTHER INFORMATION CONTACT** section.

After consideration of all relevant material presented, including the committees' recommendations, and other information, it is found that the order provisions suspended by this action no longer tend to effectuate the declared policy of the Act for the 2006–07 period. Accordingly, we are finalizing the interim final rule, without change, as published in the **Federal Register** (71 FR 78042, December 28, 2006).

List of Subjects

7 CFR Part 916

Marketing agreements, Nectarines, Reporting and recordkeeping requirements.

7 CFR Part 917

Marketing agreements, Peaches, Pears, Reporting and recordkeeping requirements.

PART 916—NECTARINES GROWN IN CALIFORNIA

PART 917—FRESH PEARS AND PEACHES GROWN IN CALIFORNIA

■ Accordingly, the interim final rule amending 7 CFR parts 916 and 917, which was published at 71 FR 78042 on September 28, 2006, is adopted as a final rule without change.

Dated: March 9, 2007.

Lloyd C. Day,

Administrator, Agricultural Marketing Service.

[FR Doc. E7–4662 Filed 3–14–07; 8:45 am]

BILLING CODE 3410–02–P

DEPARTMENT OF ENERGY

Office of Energy Efficiency and Renewable Energy

10 CFR Part 490

RIN 1904–AB67

Alternative Fuel Transportation Program; Replacement Fuel Goal Modification

AGENCY: Office of Energy Efficiency and Renewable Energy (EERE), Department of Energy (DOE).

ACTION: Final rule.

SUMMARY: DOE is publishing this final rule pursuant to the Energy Policy Act of 1992 (EPAct 1992). DOE is extending the EPAct 1992 goal of achieving a production capacity for replacement fuels sufficient to replace 30 percent of the projected U.S. motor fuel consumption (Replacement Fuel Goal) to 2030. DOE determined through its analysis that the 30 percent Replacement Fuel Goal cannot be met by 2010, as established in section 502(b)(2)(B). DOE has determined that the 30 percent goal can be achieved by 2030.

DATES: *Effective Date:* This rule is effective June 1, 2007.

FOR FURTHER INFORMATION CONTACT: To request a copy of this Final Rule notice or arrange on-site access to paper copies of other information in the docket, or for further information, contact Mr. Dana V. O'Hara, Office of Energy Efficiency and Renewable Energy (EE–2G), U.S. Department of Energy, 1000 Independence Avenue, SW., Washington, DC 20585–0121; (202) 586–9171; *regulatory_info@afdc.nrel.gov*; or Mr. Chris Calamita, Office of the General Counsel, U.S. Department of Energy, 1000 Independence Avenue, SW., Washington, DC 20585–0121; (202) 586–9507. Copies of this final rule and supporting documentation for this rulemaking will be placed at the following Web site address: *http://www1.eere.energy.gov/vehiclesandfuels/epact/private/index.html*. Interested persons may also access these documents using a computer in DOE's Freedom of Information (FOI) Reading Room, U.S. Department of Energy, Forrestal Building, Room 1E–190, 1000 Independence Avenue, SW., Washington, DC 20585–0121, (202) 586–3142, between the hours of 9 a.m. and 4 p.m., Monday through Friday, except Federal holidays.

SUPPLEMENTARY INFORMATION:

I. Introduction

On September 19, 2006, DOE published a notice of proposed rulemaking (NOPR) announcing its proposed determination that the EPAct 1992 (Pub. L. 102–486) Replacement Fuel Goal of 30 percent by 2010 is not achievable and announcing its proposal to extend the time for achieving the 30 percent replacement fuel production capacity goal to 2030. 71 FR 54771, Sept. 19, 2006.

EPAct 1992, section 502(a) directed DOE to establish a replacement fuel program. (42 U.S.C. 13252(a)) The purpose of this program is to ''promote the replacement of petroleum motor fuels with replacement fuels to the maximum extent practicable.'' (Id., emphasis added.) The focus of this program, as indicated in section 502(b)(2), is on expanding replacement fuels production capacity. (42 U.S.C. 13252(b)(2)) Further, section 502(b)(2) specifies an interim Replacement Fuel Goal of producing sufficient replacement fuels to replace 10 percent by 2000 of the projected consumption of motor fuels in the United States and a final goal of 30 percent by 2010. (42 U.S.C. 13252(b)(2)(A) and (B)) Under section 504, DOE was tasked with evaluating these goals and if DOE finds the goals to be unachievable, then DOE is directed to modify the goals so that they are achievable. (42 U.S.C. 13254(a) and (b)) In modifying the goals DOE can either modify the goal percentage or timeframe or both. (42 U.S.C. 13254(b))

In evaluating and modifying the goals, DOE must balance considerations in order to establish goals that are ''achievable.'' (42 U.S.C. 13254(b)) The Replacement Fuel Goals must promote replacement fuels to the ''maximum extent possible'' while remaining technologically and economically feasible. (42 U.S.C. 13254(a) and (b)(2)) The revised goal adopted today meets these requirements, for several reasons. First, DOE based its analysis on the best information available, from published and peer-reviewed sources. In particular, much of DOE's analysis was based on the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2005 through 2007. Second, DOE's analysis generally was based on the current budget and policy framework, under which many technologies show reasonable potential for success and market penetration. Thus, the analysis assumed virtually no major new policies or funding initiatives beyond those already in place. Third and last, the modified goal balances the minimum and maximum projected replacement fuel production capacities from several reasonable scenarios.

In the NOPR, DOE evaluated four scenarios, which identified projected replacement fuel capacities of 8.65 percent, 17.84 percent, 35.25 percent, and 47.06 percent, by 2030. (Updated analyses conducted in this final rule resulted in the first and third of these becoming 7.38 percent and 33.13 percent, respectively.) These projections reflect considerations of numerous variables including oil prices, technological breakthroughs, and market acceptance. The goal proposed by DOE fell in the mid-range among these scenarios. Also, the proposed goal did not rest upon a single technology, but instead relied on a portfolio of options. Explicit in this approach is the assumption that not all of the technologies will achieve the same measure of success; some will be more successful than others. Similarly, the proposed goal did not rely on the most advantageous market conditions.

Therefore, DOE determined that the proposed goal would meet the requirement to balance the objective of section 502(a) to promote replacement fuels to the ''maximum extent practicable'' and the section 504(b) requirement that the Replacement Fuel Goal be ''achievable.'' (42 U.S.C. 13252(a) and 13254(b))

In today's Final Rule, DOE determines that the EPAct 1992 goal of establishing sufficient replacement fuel production capacity to replace 30 percent on an energy equivalent basis of all U.S. motor fuel by 2010 is not achievable. This determination is based on a similar evaluation of the projected U.S. production capacity of replacement fuels as was presented in the NOPR. 71 FR 54711. Further, today's Final Rule extends the 30 percent Replacement Fuel Goal out to 2030 based on an analysis similar to that presented in the NOPR and discussed further below. Today's Final Rule complies with DOE's obligation under section 504(b) of EPAct 1992 to ''establish goals that are achievable, for the purposes of this title.'' (42 U.S.C. 13254(b))

Today's final rule also implements the March 6, 2006 order of the U.S. District Court for Northern District of California to prepare and publish a final rule to modify EPAct 1992's replacement fuel production goal for 2010. See *Center for Biological Diversity* v. *U.S. Department of Energy et. al.*, 419 F.Supp. 2d 1166 (N.D. Cal. 2006).

DOE reminds interested parties that the Replacement Fuel Goal is an administrative goal guiding the replacement fuel program, including administering the EPAct 1992 title V fleet mandates. It is *not* a program plan, implementation plan, national policy, or any other type of major program for achievement of the Replacement Fuel Goal. In addition, the statutory requirement for the Replacement Fuel Goal is potential production capacity. This does not require the fuel quantities implied by this goal actually be produced or used.

II. Background

A. Replacement Fuel Program

Section 502(a) of EPAct 1992 requires the Secretary of Energy (Secretary) to establish a program to promote the development and use of ''domestic replacement fuels'' and to ''promote the replacement of petroleum fuels with replacement fuels to the maximum extent practicable'' (42 U.S.C. 13252(a)). Section 502(a) states:

> The Secretary shall establish a program to promote the development and use in light duty motor vehicles of domestic replacement fuels. Such a program shall promote the replacement of petroleum fuels to the maximum extent practicable. Such program shall, to the extent practicable, ensure the availability of those replacement fuels that will have the greatest impact in reducing oil imports, improving the health of our Nation's economy and reducing greenhouse gas emissions.

(42 U.S.C. 13252(a))

Since 1992, DOE has taken a number of steps to implement EPAct 1992's replacement fuel programs, under the authority provided in titles III, IV and V of the Act. DOE coordinates various aspects of the Federal fleet's efforts to comply with the vehicle acquisition requirements established under section 303 of EPAct 1992. (42 U.S.C. 13212). DOE has also promulgated and implemented regulations and guidance for alternative fuel providers and State government fleets, which are subject to the fleet provisions contained in sections 501 and 507(o) (42 U.S.C. 13251 and 13257(o), respectively). 10 CFR Part 490. DOE also established the Clean Cities initiative, which supports public and private partnerships that deploy alternative fueled vehicles (AFVs) and build supporting infrastructure. Clean Cities works closely with both voluntary and regulated fleets in specific geographic areas, to bring together the necessary ''critical mass'' of demand for alternative fuels to support expansion of the refueling infrastructure. In addition, DOE conducts research and development on replacement fuels production and utilization technologies in conjunction with other Federal agencies (such as the U.S. Department of Agriculture (USDA)), States, private industry, and universities. All of these programs work together to increase the production and utilization of replacement fuels and improve the efficiency of vehicles.

In particular, the regulatory fleet programs have been successful in moving fleets covered under EPAct 1992 toward the use of AFVs and alternative fuels and reducing the use of petroleum fuels. The regulatory fleet programs established under EPAct 1992 have seen extremely high levels of compliance. Nearly all individual Federal agencies have met their AFV acquisition requirements, and the Federal fleet as a whole has exceeded the required 75 percent acquisition level for the last four years. Among State and alternative fuel provider fleets, compliance has also been high and DOE has been able to work out nearly all the relatively few instances of deficient acquisitions with the involved fleets, either through the fleets purchasing credits or agreeing to acquire additional AFVs in future years.

Original equipment manufacturers (OEMs) have expanded the number and type of AFV models offered, mostly due to the demand from EPAct regulated fleet programs, regulatory incentives (Corporate Average Fuel Economy (CAFE) credits), and coordinated voluntary activities (Clean Cities). In model year 1993, OEMs were only offering a handful of different AFVs models. The availability of models and fuel types has increased substantially over the past decade. During model year 2006, there were over 20 light-duty fuel/vehicle model combinations available (with more models promised over the next several years). Virtually all of these were E85 flexible fuel vehicles (FFVs). Overall, there are now on the order of one million FFVs manufactured annually in the U.S., largely to take advantage of the CAFE benefits. At the same time, the regulated fleets do acquire many of these vehicles each year.

The Replacement Fuel Program efforts have also assisted in expanding the infrastructure for alternative fuels. In 1992 when EPAct was passed, there were not that many alternative fuel refueling stations in operation (approximately 3,600) and nearly all were for propane. Today, there are approximately 5,400 alternative fuel refueling stations in the U.S., including over 1,000 E85 stations in operation, with several hundred coming on-line each year over past few years. There are also many more compressed natural gas (CNG) stations than in 1992, although this number has begun to decrease slightly in the last few years as OEM offerings have dwindled. (For the current number and location of alternative fuel refueling stations, visit the Alternative Fuel Data Center (AFDC) station locator, *http://www.eere.energy.gov/afdc/infrastructure/refueling.html.*) This overall growth in stations has been primarily through the demand generated through the regulated fleets and related voluntary efforts under Clean Cities. The number of alternative fuel refueling stations remains small when compared to the 180,000 total refueling stations Nationwide, but is projected to continue increasing.

In the State of the Union address in January 2006, the President announced the Advanced Energy Initiative (AEI), which focuses on increasing the use of non-conventional fuels like replacement fuels in all sectors of the U.S. economy, with a central focus on the transportation sector. AEI sets out an aggressive course for reducing the

Nation's dependence on foreign petroleum, setting a national goal of replacing more than 75 percent of the U.S. imports from foreign sources by 2025. AEI emphasizes technology developments as the key to reducing energy dependence, including several of the same technologies such as efficiency improvements, biofuels, and hydrogen. These appear under the portion of the Initiative focused on ''Changing the way we fuel our vehicles.'' AEI is available on the White House Web site at the following location: *http://www.whitehouse.gov/stateoftheunion/2006/energy/*.

On January 23, 2007, the President, in the State of the Union Address, proposed replacing 20 percent of the projected gasoline usage in 10 years (''Twenty in Ten'' initiative). Twenty in Ten builds on the foundation established by the AEI from the previous year's State of the Union Address with two major elements relevant to today's final rule. The first element is to increase the use of alternative fuels to 35 billion gallons in 2017, reducing projected gasoline consumption by 15 percent, through advancements in many fields including cellulosic ethanol, butanol, and biodiesel. In the second element of Twenty in Ten, the President has asked Congress to give the Administration authority to reform the fuel efficiency system for passenger cars, as was recently done for light trucks and sport utility vehicles (SUVs). It is estimated that the projected gains in mileage for passenger cars could save another 5 percent of our projected gasoline usage in 2017.

The Twenty in Ten initiative, which sets a goal for 2017, is consistent with the Replacement Fuel Goal adopted today. However, there are several notable differences. First, DOE notes that the Twenty in Ten initiative relates to projected gasoline consumption, whereas today's final goal relates to projected gasoline and diesel fuel consumption. Second, the Replacement Fuel Goal is established in terms of energy equivalency, where as the Twenty in Ten initiative is in terms of absolute volume. Third, while the Twenty in Ten initiative emphasizes the same elements as the Replacement Fuel Goal, the Twenty in Ten initiative is more aggressive than the revised goal in terms of assumptions of increased fuel efficiency of light trucks and passenger cars and increased use of renewable and alternative fuels to replace a significant portion petroleum usage.[1]

The more aggressive components of the Twenty in Ten initiative are based on policy and legislative actions proposed by the President that were not considered in today's final rule. The final rule generally considered only policies and programs currently in place, and therefore the policies proposed in the Twenty in Ten initiative were not considered in today's final rule. DOE intends to continue monitoring the Twenty in Ten initiative as policies and programs begin to develop, and will determine if the Replacement Fuel Goal requires additional modification. The Twenty in Ten initiative is available on the White House Web site at: *http://www.whitehouse.gov/stateoftheunion/2007/initiatives/energy.html*.

B. Replacement Fuel Goals

As previously discussed, section 502(a) requires DOE to implement a replacement fuel program. Under such program the Secretary is required to review appropriate information and estimate the production capacity for replacement fuels and AFVs. The Secretary also has to determine the technical and economical feasibility of achieving the capacity to produce on an energy equivalent basis, 10 percent of the projected motor fuel in the U.S. in 2000 and 30 percent in 2010. Section 502(b) established production goals for replacement fuels, and states:

(b) Development Plan and Production Goals—[T]he Secretary * * * shall review appropriate information and—

* * * * *

(2) Determine the technical and economic feasibility of achieving *the goals of producing sufficient replacement fuels* to replace, on an energy equivalent basis—

(A) At least 10 percent by the year 2000; and

(B) At least 30 percent by the year 2010, of the projected consumption of motor fuel in the United States for each such year, with at least one half of such replacement fuels being domestic fuels[.]

(42 U.S.C. 13252(b)(2)) (Emphasis added.) Thus section 502(b) sets two goals, an interim goal of developing sufficient U.S. domestic replacement fuel production capacity to replace 10 percent of projected total motor fuel use by the year 2000, and a final goal of 30 percent by the year 2010, with at least one half of such replacement fuels being domestic fuels. (42 U.S.C. 13252(b)(2)(A) and (B))

While the goals in section 502(b) and the programs established under section 502(a) are related, the goals are not mandates for the programs. Today's review of the Congressional goals is in the context of the section 502(a) programs. Section 502(b) states that, ''under the programs established under subsection (a), the [DOE] * * * shall review appropriate information and'' evaluate the achievability of the goals. (42 U.S.C. 13252(b)) Further, in the context of the section 502(a) programs, DOE must ''determine the most suitable means and methods of developing and encouraging the production, distribution, and use of replacement fuels and alternative fueled vehicles[.]'' (42 U.S.C. 13252(b)(3)) As discussed above, DOE has established various programs to implement the goals of sections 502(a) and (b). However, no where in the text of section 502 are the goals established as mandates for the section 502(a) programs.

Pursuant to section 504 of EPAct 1992, DOE is required to review these goals periodically and publish the results and provide opportunities for public comments. (42 U.S.C. 13254(a)) If DOE determines that the goals are not achievable, section 504(b) directs DOE to modify, by rule, the percentage requirements and/or dates, so that the goals are achievable. (42 U.S.C. 13254(b)) DOE has determined that in order for a goal to be achievable, there must be a reasonable expectation that the desired level of replacement fuels production capacity will develop within the relevant timeframe.

While DOE has authority to modify the section 502(b) goals, DOE's authority to establish requirements under the replacement fuel and alternative fuel programs is limited. Section 504(c) provides DOE the authority to issue regulations if the achievement of the Replacement Fuel Goals contained in section 502(b) are likely to lead to ''a significant and correctable failure'' to meet the overall program goals established by section 502(a). (42 U.S.C 13254(c)) However, EPAct 1992 does not provide DOE the authority ''to mandate marketing or pricing practices, policies or strategies for alternative fuel, or to mandate the production or delivery of such fuels.'' (42 U.S.C. 13254(c)) Further, DOE's authority to

[1] The President's initiative notes that given the changing nature of the marketplace for both cars and light trucks, the Secretary of Transportation would determine in a flexible rulemaking process the *actual* fuel economy standard and accompanying fuel savings. Additionally, under the Twenty in Ten initiative the EPA Administrator and the Secretaries of Agriculture and Energy will have authority to waive or modify the required levels of alternative and renewable fuel use if they deem it necessary, and the new fuel standard will include an automatic ''safety valve'' to protect against unforeseen increases in the prices of alternative fuels or their feedstocks.

require the use of alternative fuels is limited.[2]

C. Definitions

The term ''*replacement fuel*'' is defined by EPAct 1992 to mean ''*the portion of any motor fuel* that is methanol, ethanol, or other alcohols, natural gas, liquefied petroleum gas, hydrogen, coal derived liquids, fuels (other than alcohols) derived from biological materials, electricity (including electricity from solar energy), ethers,'' or any other fuel that the Secretary determines meets certain statutory requirements. (42 U.S.C. 13211(14)) (Emphasis added.)

The term ''*alternative fuel*'' is defined to include many of the same types of fuels (such as ethanol, natural gas, hydrogen, and electricity), but also includes certain ''mixtures'' of petroleum-based fuels and other fuels as long as the ''mixture'' is ''substantially not petroleum.'' (42 U.S.C. 13211(2) and 10 CFR 490.2) Thus, a certain mixture might constitute an ''alternative fuel,'' but only the portion of the fuel that falls within the definition of ''replacement fuel'' would actually constitute a ''replacement fuel.'' For example, M85, a mixture of 85 percent methanol and 15 percent gasoline, would, in its entirety, constitute an ''alternative fuel,'' but only the 85 percent that was methanol would constitute ''replacement fuel.'' Also by way of example, gasohol (a fuel blend typically consisting of approximately 10 percent ethanol and 90 percent gasoline) would not qualify as an ''alternative fuel'' because it is not ''substantially not petroleum,'' but the 10 percent that is ethanol would qualify as ''replacement fuel.''

Section 301(12) of EPAct 1992 defines ''motor fuel'' as ''any substance suitable as fuel for a motor vehicle.'' (42 U.S.C. 13211(12)) Moreover, the term motor vehicle is defined in EPAct 1992 section 301(13), through reference to 42 U.S.C. 7550(2), as a self-propelled vehicle that is designed for transporting persons or property on a street or highway. (42 U.S.C. 13261(13)) The goals established in section 502(b)(2) require that DOE evaluate the capacity of producing sufficient replacement fuels to offset a certain percentage of U.S. ''motor fuel'' consumption. Therefore, DOE, for the purposes of Title V of EPAct 1992, has interpreted the term motor fuel to include all fuels that are used in motor vehicles. This includes fuels used in light-, medium-, and heavy-duty on-road vehicles. 71 FR 54771 (September 19, 2006).

D. Previous Review of the Goals

Section 504(a) of EPAct 1992 requires DOE to periodically ''examine'' the goals established in section 502(b)(2) and determine whether they should be modified. (42 U.S.C. 13254(a)) The examination of the goals is to be made taking into account the program goals stated under section 502(a), namely to promote the development and use of ''domestic replacement fuels'' and to ''promote the replacement of petroleum fuels with replacement fuels to the maximum extent practicable.'' (42 U.S.C. 13254(a))

As an initial matter, DOE notes that it is unaware of any analysis or technical data that was used by Congress in 1992 as a basis for setting the 10 percent and 30 percent Replacement Fuel Goals set forth in EPAct 1992. DOE is also not aware of any affirmative determination by Congress or by any agency that, at the time they were set, the statutory goals were explicitly considered achievable. Thus, DOE has treated these replacement fuel production capacity levels as the starting point for future goal analyses. Regardless of the original rationale for the goals, and as described and discussed below, DOE periodically has evaluated the feasibility of the goals as provided by Congress in EPAct 1992.

Several previous efforts were made by DOE to analyze the Replacement Fuel Goal. The first effort was in 1996, as part of the Assessment of Costs and Benefits of Flexible and Alternative Fuel Use in the U.S. Transportation Sector, Technical Report Fourteen: Market Potential and Impacts of Alternative Fuel Use in Light-Duty Vehicles: a 2000/2010 Analysis (U.S. Department of Energy, Office of Policy and Office of Energy Efficiency and Renewable Energy, January 1996, report number DOE/PO–0042), to be referred to as Technical Report 14.

The second major attempt by DOE to evaluate the replacement fuel picture was made at the end of the last decade, in the report Replacement Fuel and Alternative Fuel Vehicle Analysis Technical and Policy Analysis, Pursuant to Section 506 of the Energy Policy Act of 1992 (U.S. Department of Energy, Energy Efficiency and Renewable Energy, Office of Transportation Technologies, December 1999 with amendments September 2000), hereinafter section 506 report. The report is available at *http://www.eere.energy.gov/vehiclesandfuels/epact/pdfs/plf_docket/section506.pdf*.

The next report to consider the achievability of the Replacement Fuel Goals was the Transitional Alternative Fuels and Vehicles (TAFV) Model Report. See The Alternative Fuel Transition: Results from the TAFV Model of Alternative Fuel Use in Light-Duty Vehicles 1996–2000 (ORNL.TM2000/168) (September 17, 2000). This report was completed shortly after the section 506 report. It examined multiple pathways toward increased replacement and alternative fuel use. The major difference between the TAFV report and earlier reports is that it used a dynamic transitional model to analyze potential replacement fuel pathways. Many of the earlier studies and analyses used single-period equilibrium models and also assumed no transitional barriers to increased alternative fuel and replacement fuel use. The TAFV report includes a number of scenarios that assume no transitional barriers but it also includes multiple pathways that do include analysis of transitional barriers. The report is available for review at: *http://www.eere.energy.gov/vehiclesandfuels/epact/pdfs/plf_docket/tafv99report31a_ornltm.pdf*.

In summary, Technical Report 14, prepared only three years after EPAct 1992's passage, did indicate that the 2010 goal could be achieved, albeit only under several scenarios relying upon extensive policy additions. The section 506 report and TAFV Report both concluded that it would be difficult and unlikely, but not impossible, to achieve the 30 percent EPAct 1992 Replacement Fuel Goal by 2010. In neither of the latter reports, issued in mid to late 2000, did DOE make a determination under EPAct 1992 section 504(b) that the statutory Replacement Fuel Goals were not achievable. If DOE had made such a determination, it would have triggered a statutory obligation to set a new, achievable, Replacement Fuel Goal. Instead, DOE chose to take a ''wait and see'' approach regarding the need to revise the 2010 goal. A much more detailed discussion on each of the three reports and their conclusions was provided in section III. of the NOPR. 71 FR 54773, Sept. 19, 2006.

E. Previous Rulemakings and Court Order

Section 507(c) directed DOE to issue an Advanced Notice of Proposed Rulemaking (ANOPR) that, in part, would evaluate the progress toward achieving the Replacement Fuel Goal and assess the adequacy and practicability of the goal. (42 U.S.C. 13257(c)) In response to that directive, DOE issued an ANOPR on April 17, 1998, 63 FR 19372. DOE conducted three public hearings (Minneapolis,

[2] Fleets are not required to use alternative or replacement fuel in their AFVs (except for alternative fuel providers and Federal Fleet, which are required by section 501(a)(4) and 303 of EPAct, respectively).

Minnesota; Los Angeles, California; and Washington, DC) and solicited written comments from the public on the ANOPR. More than 110 interested parties responded by providing written and oral comments. Comments were received through July 16, 1998.

In the ANOPR, DOE requested comments on 23 specific questions covering three broad areas: replacement fuels, fleet requirements, and urban transit buses. Only the first set of questions is relevant to today's rulemaking. A detailed discussion of these comments was previously provided in the NOPR for the Private and Local Government Fleet Determination (68 FR 10320, 10326–10328; March 3, 2003) and a summary of those comments was provided in the Replacement Fuel Goal NOPR. 71 FR 54771, Sept. 19, 2006.

Additionally, DOE previously addressed the issue of whether to revise the replacement fuel production goal for 2010 in the context of its determination that an AFV acquisition mandate for private and local government fleets was not necessary. 69 FR 4219 (January 29, 2004). Section 507(e) directs DOE to consider whether a fleet requirement program for private and local fleets is "necessary" for the achievement of the Replacement Fuel Goals. (42 U.S.C. 13257(e)) As part of DOE's decision under that directive, DOE stated in its notice of final rulemaking that a private and local government fleet rule would "not appreciably increase the percentage of alternative fuel and replacement fuel used by motor vehicles." 69 FR 4220, Jan. 29, 2004. DOE further concluded that "adoption of a revised goal would not impact its determination that a private and local government rule * * * would not provide any appreciable increase in replacement fuel use." 69 FR 4221, Jan. 29, 2004. DOE, therefore, did not revise the Replacement Fuel Goal at the time but indicated that it would continue to evaluate the need to revise the statutory goal in the future.

Subsequent to the publication of the January 29, 2004 final rule, DOE was sued in Federal court by the Center for Biological Diversity (CBD) and Friends of the Earth for failing to impose a private and local government fleet acquisition mandate and for not revising the replacement fuel production goal for 2010 as part of its determination. On March 6, 2006, the U.S. District Court for the Northern District of California vacated DOE's final determination regarding the private and local government fleet mandate and ordered DOE to revise the replacement fuel production goal for 2010. (See *Center for Biological Diversity*, 419 F.Supp. 2d 1166.) In its order, the Court directed DOE to prepare notices of proposed rulemaking and final rules on both the Replacement Fuel Goal for 2010 and the private and local government fleets determination. (Id. at 1171.)

F. NOPR for the Replacement Fuel Goal

DOE proposed to revise the 30 percent by 2010 goal by extending the goal date to 2030. 71 FR 54771, Sept. 19, 2006. DOE based the proposed revised goal on an analysis which focused on projected production capacity for replacement fuels through 2030. DOE based the proposal on four reference cases, which were based on three building blocks. The three building blocks are: (1) The reference case projected by EIA in AEO 2006; (2) the high price case presented in AEO 2006; and (3) projections from the DOE programs conducting research and development on replacement fuel and vehicle technologies. These building blocks provide the basis for the reference cases which project varying levels of potential replacement fuel production capacity.

The four scenarios relied upon in the NOPR analysis were: (1) The reference case projected by EIA in AEO 2006; (2) the high price scenario presented in AEO 2006; (3) a combination of the AEO 2006 reference case with achievement of program goals (designated as program developments); and (4) a combination of the AEO 2006 high price case with program developments. The different scenarios represent the potential bounds for proposing a revised replacement fuel production goal under sections 502 and 504 of EPAct 1992. Under a 2030 timeframe, these scenarios projected a replacement fuel production capacity as a percent of on-road fuel use of 8.65 percent, 17.84 percent, 35.25 percent, and 47.06 percent, respectively. 71 FR 54782–3, Sept. 19, 2006.

As presented in the NOPR, DOE proposed to maintain the 30 percent goal and move the goal date out 20 years, to 2030. 71 FR 54785, Sept. 19, 2006. Given the uncertainties inherent in projecting fuel prices and technology achievements, DOE tentatively determined that a goal slightly above the midpoint of the projections of the four reference cases represented an "achievable" goal as required by section 504(b). (42 U.S.C. 13254(b))

A detailed discussion of the building blocks and the reference cases is provided in section V. of the NOPR. 71 FR 54776, Sept. 19, 2006. Today's final rule relies on essentially the same analysis framework, with updated projections by the EIA. The analysis framework and results are summarized below.

III. Comments

A. Comments Received

The NOPR solicited comments on the proposed Replacement Fuel Goal modification. Written comments were received from a total of sixteen organizations. This included the following four specific organizations providing substantive comments:

- The American Automotive Leasing Association (AALA),
- The CBD/Friends of the Earth,
- The National Association of Fleet Administrators (NAFA), and
- NGVAmerica.

The other twelve sets of comments were from Clean Cities coordinators or stakeholders, or were organizations that were not identified specifically as related to Clean Cities, but which provided similar type or level of comments to those received from the Clean Cities organizations. Thus, for most of the discussion below, these Clean Cities and related comments were grouped together. These organizations included:

- Central Texas Clean Cities.
- City of Victoria.
- DieselGreen/Austin Biodiesel Cooperative.
- Granite State Clean Cities.
- Greater New Haven Clean Cities Coalition, Inc.
- Greater New Orleans Regional Planning Commission.
- Kansas City Clean Cities.
- Maine Clean Communities.
- Norwich Clean Cities.
- Public Solutions Group, Ltd./Central Texas Clean Cities.
- St. Louis Clean Cities.
- Synetek Research Co.

It should be noted that within these comments, most Clean Cities organizations utilized a common framework for their comments, relying upon shared key points. Within these organizations, however, two (Granite State Clean Cities and Maine Clean Communities) provided somewhat more expansive and detailed comments.

On October 3, 2006, DOE held a hearing at DOE headquarters in Washington, DC. Approximately one dozen people attended, including representatives from AALA, NGVAmerica, several media organizations, and DOE program staff and related personnel. In addition, one member of the general public also attended. A list of attendees is available at *http://www1.eere.energy.gov/vehiclesandfuels/epact/pdfs/plg_docket/hearing_attendee_list.pdf*.

Program technical staff presented a short overview of the rulemaking process (available at *http://www1.eere.energy.gov/vehiclesandfuels/epact/pdfs/plg_docket/ohara_presentation.pdf*). No entities prepared or delivered detailed testimony at this hearing. Discussions during the hearing were relatively short and of a much more general nature with all points raised also included within the written comments received. Therefore, no separate discussion of the comments from the hearing is necessary. The transcript from this hearing is available at *http://www1.eere.energy.gov/vehiclesandfuels/epact/pdfs/plg_docket/hearing_transcript.pdf*.

Due to technical difficulties in receiving comments on the NOPR electronically, on January 18, 2007, DOE published a limited re-opening of the comment period; 72 FR 2212, Jan. 18, 2007. This notice re-opened the comment period until January 31, 2007. During this additional period, one additional set of comments was received from the National Propane Gas Association (NPGA).

B. Discussion of Comments

In order to address the comments in a clear manner, they were split out into several basic categories. These include:

- Approach—comments concerning DOE's approach to addressing its requirements concerning evaluating and modifying the Replacement Fuel Goal;
- Goal—comments concerning the level and time-frame for the proposed modified goal, schedule for review of the modified goal, and whether an interim goal was necessary;
- Assumptions—comments concerning the detailed assumptions made by DOE in its analysis; and
- Programmatic/DOE's Role—comments concerning possible programs or DOE's overall role concerning achievement of the Replacement Fuel Goal.

In addition to identifying the comments in each section below, the discussion of the final analysis further addresses, where appropriate, specific issues raised by commenters.

Approach

One commenter indicated that DOE's interpretation of ''achievable'' was reasonable, and that the current goal needed to be modified. This commenter also indicated that DOE was correct to focus on more than just a single technology, and on the entire fuel supply chain. Another commenter also indicated that DOE should base the revised goal upon reductions across the entire transportation sector, and not just regulated fleets. In response, DOE reiterates that it did base its approach upon a number of technologies and fuels, and did look at fuel savings and substitution within the entire on-road transportation sector. As indicated in the NOPR, DOE looked at the entire highway transportation sector in determining the Replacement Fuel Goal. DOE also looked at technologies such as hybrids, fuel cell vehicles, advanced energy efficient vehicles, and dual-fuel/FFVs. The fuels used in the analysis included ethanol, biodiesel, natural gas, coal to liquids, gas to liquids, and hydrogen. 71 FR 54771, Sept. 19, 2006.

Different opinions were expressed concerning DOE's approach with respect to determining if the Private and Local Government Fleets Rule is necessary. One commenter specifically indicated its satisfaction with the approach taken by DOE, while another specifically indicated its objection. A third commenter simply cautioned DOE to resist the urge to set a new Replacement Fuel Goal level solely for the purpose of justifying a Private and Local Government Fleet Rule. This same commenter spent the majority of its comments stating why such a fleet rule is wrong.

In response, DOE is focused only on the development of an achievable goal that meets the requirements of sections 502(a) and 504(b) of EPAct 1992 in this rule. DOE is not predisposed to any outcome beyond setting the goal. The Private and Local Government Fleet Rule determination is a separate rulemaking process from the Replacement Fuel Goal modification, and DOE is continuing to treat these as separate processes. The fleet rule determination will not be commenced until the revised Replacement Fuel Goal is set, and the determination process will specifically include an opportunity for comment on a proposed determination prior to development of the final determination.

Goal/Schedule/Interim Goal

Two specific commenters plus a number of the Clean Cities and related organizations objected to what they stated is a 20-year delay in the goal, from 2010 to 2030. They indicated that a more progressive goal is needed, and one that has a stronger focus upon program development and implementation. Similarly, one of the individual commenters indicated that it did not understand why the inability to meet the goal in 2010 permits a 20-year delay. While a number of these commenters indicated that they wanted to see DOE set a ''higher goal,'' few offered concrete proposals as to what that goal should be and how it would be achievable. Two Clean Cities coordinators did specifically suggest that DOE select one of the more accelerated paths included within its NOPR analysis, such as utilizing one of the ''program development'' cases. At the same time, one commenter felt that DOE's proposed goal was reasonable, based upon comparison to similar actions of States and several foreign governments.

In response to commenters requesting a more aggressive goal than what was proposed, DOE notes that it has a statutory obligation to balance certain considerations in order to establish goals that are ''achievable.'' (42 U.S.C. 13254(b)) The replacement fuel production capacity goals must promote replacement fuels to the ''maximum extent possible'' while at the same time remaining technologically and economically feasible. (42 U.S.C. 13254(a) and (b)(2)) DOE interprets ''achievable'' to mean that there is a reasonable expectation of reaching the goal in the time period specified. DOE considered the various options within the current budgetary and policy framework and selected what DOE determined is a goal which is set at the ''maximum extent practical'' and still ''achievable.'' The current EIA baseline projection for replacement fuels by 2030 is only 7.38 percent. Today's analysis indicated that if all DOE's technical programs were as successful as predicted and the technologies were fully adopted in the marketplace, the maximum replacement fuel that could be achieved is 33 to 47 percent. To expect DOE to be 100 percent successful in its development programs is unreasonable. By their very nature, many of the research programs are high risk.

One individual commenter and several Clean Cities and related organizations generally claimed that there are significant environmental, energy security, and economic impacts in delaying the goal. However, the commenters did not provide specific estimates of these potential impacts or how moving the goal to 2030 would result in such impacts.

One individual commenter and two Clean Cities coordinators specifically called for DOE to set an interim goal. DOE notes that in the Court's order directing DOE to revise the Replacement Fuel Goal, the Court focused almost entirely upon the 2010 goal. (*Center for Biological Diversity*, 419 F.Supp. 2d 1166.) Further, the Court clearly directed DOE to revise the ''goal.'' (*Center for Biological Diversity* v. *U.S.*

Dept. of Energy et. al., No. 05–cv–01526–WHA Document 54 p. 2 (N.D. Cal. March 30, 2006) (*Order re Timing of Relief*)) The Court's use of ''goal'' in the singular provides direction to revise the 2010 goal, and DOE developed the NOPR accordingly.

To the extent that an ''interim goal'' allows the public to understand the trajectory of the replacement fuel production necessary to meet the 2030 goal, DOE's analysis developed data points at 2020, 2025 and 2030 for all four scenarios evaluated. The charts provided below indicate a range of percentages which provide benchmarks for evaluating progress towards the achieving the goal. Moreover, the annual publication of EIA analyses of replacement fuel contributions in the Annual Energy Review (AER) and AEO provides an indication of progress. For example, the replacement fuel production capacity levels were estimated in the range between approximately 6 and 17 percent in the NOPR for 2020. As updated in the analysis for this final rule, the two 2020 reference case-based scenarios project a replacement fuel capacity between 5 and 14 percent. DOE and the public will be able to compare the AEO projections and AER data to the Replacement Fuel Goal analysis presented in today's final rule and the NOPR.

Two commenters specifically requested that DOE provide a specific schedule for reviewing the Replacement Fuel Goal in the future. These commenters stated that the information resulting from such reviews should be published more frequently. The statutory requirement in section 504(a) is for periodic review. As discussed above, EIA publishes the AEO report annually, which estimates the replacement fuel production capacity of the U.S. DOE will review the annual AEO reports and based in part on these reports determine whether a more comprehensive review of the Replacement Fuel Goal is warranted.

Finally, a commenter specifically indicated that ''DOE should note that future reviews may also result in modifying the goal to reduce the timeframe or increase the replacement fuel percentage if achievable in order to effectuate the intent of the Act and the Replacement Fuel Program.'' DOE acknowledges that if future reviews show results more or less favorable to achievement of the goal, then DOE could increase/decrease the level or accelerate/push out the date. DOE has no pre-conceived concepts as to what any future reviews of progress toward the goal will show. The statutory requirement of the periodic review is for DOE to evaluate the goal and determine if the goal is practical and achievable. If the goal is not achievable, DOE has the responsibility to develop an achievable goal that is ''technically and economically feasible'' and promotes replacement fuels to the ''maximum extent practicable'' in a specific timeframe, whatever that may be.

Analysis Assumptions

One individual commenter and two Clean Cities coordinators stated that the future oil prices upon which DOE based its analyses should have been much higher. Therefore, these commenters asserted, the decision on replacement fuel penetration levels should have been closer to the EIA high price case, or even based on prices higher than EIA's high price case. In response, DOE determined that it was inappropriate to assume significantly higher fuel prices than those presented in the AEO reports without a sufficient basis upon which to determine such prices. A case in point: there has been a significant drop in the cost of crude oil since the publication of the NOPR on September 19, 2006. Last summer crude prices were over $70 per barrel, but prices had fallen below $50 per barrel by late January, 2007. (EIA Petroleum Navigator at *http://tonto.eia.doe.gov/dnav/pet/pet_pri_wco_k_w.htm*) In addition, EIA analysis from AEO Reports indicates that higher oil prices do encourage more replacement fuel usage and increased energy efficiency. However, higher oil prices also cause drivers to use less petroleum overall. This coupled with the increased use of replacement fuels and increased energy efficiency can cause oil prices to fall.

DOE is required to develop a goal that is achievable. Commenters did not provide any data to justify reliance on abnormally high oil prices for a sustained period or years. Therefore, DOE based its analysis upon EIA analyses. If projections for future prices increase significantly, DOE will review the annual AEO and based in part on these reports determine whether further review of the Replacement Fuel Goal is warranted.

One commenter indicated that it felt DOE underestimated the contribution of conservation in the overall analysis. In response, DOE did address conservation, and believes that conservation was given a sizable role in both of the program development cases. The program development cases included energy efficiency gains from hybrids, advanced diesels, and fuel cell vehicles. The EIA data only takes into account the annual energy efficiency gains that vehicles have gained historically, typically around 1.2 percent. As presented in the NOPR, DOE analyzed two cases that incorporated savings of approximately 3 million barrels per day in 2030, above and beyond any conservation efforts already taken into account in EIA data.

One commenter stated that DOE's assertion that research and development programs will accomplish their goals is unrealistic, and thus contradicts DOE's approach to ''achievable.'' DOE notes that it used approximately a 50 percent, not 100 percent, success rate for all of DOE's programs in arriving at the final Replacement Fuel Goal. As reflected in the NOPR, estimates for the maximum contributions from successful commercialization of technologies resulting from DOE research and development to the overall goal by 2030 were no more than 30 percent replacement fuel. The two EIA base cases (reference and high price (NOPR Tables 1 and 2)) projected levels of approximately 9 to 18 percent replacement fuel. Adding approximately half of the DOE research and development technologies to the EIA base cases results in projected levels of approximately 24 to 33 percent replacement fuel. Therefore, DOE proposed in the NOPR a goal within the range of the identified scenarios, and did not rely upon DOE research and development programs achieving all of their goals.

One commenter plus a number of Clean Cities-related organizations specifically questioned the Department's exclusion of plug-in hybrid electric vehicles (PHEVs) as inadequate, and disagreed with projections showing that the contribution from electricity would not grow significantly during the period of the analysis. No commenter submitted any data supporting a more concrete role for these vehicles, or what their overall effect would be. As stated in the NOPR, DOE has determined that it is premature to specifically evaluate this new technology, especially to the level of detail of the analysis done for this action. DOE recognizes that PHEVs offer a significant potential for reducing petroleum use in the U.S. transportation sector. As such, PHEVs were evaluated as part of the total hybrid vehicle market analysis. Modeling used for this analysis indicates that conventional, flex-fuel, and PHEVs as well as fuel-cell hybrids will be vying for the same market segments by 2030. The entire market segment was evaluated and significant gains in fuel efficiency and replacement fuels were indicated. However, DOE does not have sufficient data to evaluate the specific contributions to petroleum

reduction attributable to PHEVs. Furthermore, DOE notes that its analysis is based upon replacement fuels competing in the marketplace. Nothing in the 30 percent goal prevents PHEVs from capturing a larger share of the replacement fuel market than is indicated by DOE's analysis. If PHEVs develop quickly and impact the relative contributions of electricity and energy efficiency relied upon in the current analysis, DOE will take notice and determine if the Replacement Fuel Goal requires additional modification.

Considerable analysis was done in the NOPR scenario 3 to determine what the vehicle sales would have to be in order to generate a demand for replacement fuel commensurate with a 35 percent Replacement Fuel Goal by 2030. 71 FR 54783. The VISION results are in Figures 5 and 6 in the NOPR. 71 FR 54784. For a level of replacement fuel demand that would be equivalent to the replacement fuel production capacity under a 35 percent by 2030 Replacement Fuel Goal, the VISION model projected that non-conventional light-duty vehicles would comprise 99 percent of new LDV sales in that model year. The breakdown of the LDVs were FFVs—24 percent of new vehicle sales; Hybrids—37 percent of new vehicle sales; Diesels—22 percent of new vehicle sales; Fuel Cell Vehicles—15 percent of new vehicle sales; and other AFVs—1 percent of new vehicle sales.

Similarly, two commenters and several Clean Cities-related organizations indicated that they felt the potential from natural gas and gas-to-liquids (GTL) was underestimated. One of these commenters also raised environmental concerns about GTL. Thus it was unclear whether this particular commenter wanted a greater role shown for this technology or not. In response to the overall concerns about potential for any particular technology, DOE relied upon the best information it had available, relying primarily upon the EIA AEO data. Neither commenter nor the Clean Cities-related organizations submitted specific data on these or other technologies.

In general, however, even if the contribution of a particular technology (whether natural gas, GTL, PHEVs, or others) were increased, DOE would anticipate that much of this change might be at the expense of another included technology. As presented above, the total level of replacement fuel usage is relatively fixed. Thus, the gains for one technology will likely be offset by reductions in another technology, as opposed to increasing the number of non-conventionally fueled motor vehicles. Therefore, given that other replacement fuels may have a larger share of the market than our analysis might otherwise indicate, the overall results for replacement fuel production capacity will remain the same. Should better data become available DOE will review it and revise the goal as necessary.

One commenter also questioned EIA's projections about coal-to-liquids (CTL), since current oil prices already appear above the level needed for economic parity, but plants have not been built. As discussed in the NOPR, having economic parity now or achieving it only recently does not mean that the plants would already be in place. As DOE indicated in the NOPR, financial investors often need to see current and projected conditions that appear favorable for several years before they are moved to act. Once investment begins, it can be a number of years before any plants are on-line. Today, some of this initial investment appears to be happening, since conditions now appear favorable, but it may be many years before significant contributions are anticipated from this technology. In addition, as shown in section V.E. below, under the updated analysis based upon the AEO 2007, the projected contribution from CTL decreased significantly.

One commenter indicated that it was unclear if DOE used Government Performance and Results Act (GPRA) analyses, or if not, why not. DOE did use GPRA analyses for a number of the program developments technologies, as indicated in the NOPR. 71 FR 54777, 54778, 54781. Two such examples are the energy efficiency gains from the FreedomCAR and Vehicle Technologies (FCVT) program and in the Hydrogen Fuel Cell and Infrastructure Technologies (HFCIT) Program (commonly referred to as the ''Hydrogen Program'') in the building blocks section (V.B.3) of the NOPR. 71 FR 54777. Where current analyses existed for technology programs, they were used. Item D11 in the electronic docket (available at *http://www1.eere.energy.gov/vehiclesandfuels/epact/private/plg_docket.html*) specifically provides a link to EERE's GPRA analyses for all relevant technology programs.

One commenter questioned whether DOE's analysis assumed new Federal incentives for certain fuels, but not for others (particularly natural gas). This commenter also indicated that DOE needed to explain how different fuels react differently to higher prices. Generally, DOE did not assume new incentives or policies that would promote a specific alternative fuel. In the limited instances in which a new policy was assumed, DOE identified its assumptions, which were based upon information received from EIA or the relevant technology programs.

One instance in which policies beyond those existing were assumed was for the hydrogen and fuel cell technologies. These technologies were identified as an exception because DOE recognizes that they will need additional support later in getting the technology into the market. Most of the other replacement fuels and technologies are viable in the market or they have or are getting tax breaks, subsidies, or other price supports until they become market viable. In order for fuel cell technologies to have the same opportunities in the market they may require similar types of support as previous technologies as well as potentially new types of assistance.

One commenter indicated that DOE did not adequately address the benefits of other Federal, State, local, and private efforts, including other EERE, FCVT, and USDA activities. In particular, this commenter indicated that DOE should include a discussion of other efforts and indicate how the President's AEI fits in. The commenter did not indicate specific programs that should be included in DOE's analysis that would contribute significantly to the Replacement Fuel Goal. It should be noted that DOE did much of what this commenter claims it did not. In particular, the ''program developments'' scenarios were specifically based upon EERE and FCVT efforts, and DOE did discuss the AEI in section VI.B. of the NOPR. 71 FR 54786. DOE also is working with USDA in development of biofuels especially in the area of cellulosic ethanol. In preparing this final rule, DOE has taken into account the Renewable Fuel Standard (RFS) from EPAct 2005 and also considered the Twenty in Ten initiative.

The same commenter indicated that DOE did not address the utilization side of the equation sufficiently. Again, the Replacement Fuel Goal is a production capacity goal, not a utilization goal. However, DOE recognizes that production and use are related. DOE did look at utilization in the VISION modeling, provided in tables 5 and 6 of the NOPR. 71 FR 54784. Moreover, the commenter failed to provide data for a revised analysis to reflect the commenter's concern.

One commenter pointed out perceived discrepancies between the EIA and VISION model analyses concerning the makeup of the LDV market. While DOE acknowledges that these two analyses differ somewhat in

their pathways, they are in relative agreement on the overall destination points. DOE analysis looked at the potential capacity to produce replacement fuels as required by section 502(a) and (b). In order to validate that data, a second analysis was performed using a fuel usage model. The VISION model looked at what replacement fuels could be used in what type of vehicles based on available knowledge of the different vehicle technologies. The total replacement fuel figures were very similar even though there were slight variations of the fuel mix and vehicle technologies. These simply show two different paths to the same result, based upon the particular assumptions of their analysts and the mechanisms within the models. DOE is not stating any one specific fuel or technology advancement, or specific set of advancements, has to occur for the Replacement Fuel Goal to be achieved. DOE believes that a portfolio of technologies, some indicated here, as well as possibly some that were not included, are required to achieve any goal.

Finally, one commenter took particular issue with DOE's approach to its greenhouse gas (GHG) analysis. This commenter stated that DOE used the wrong baseline for assessing GHG emissions. The commenter indicated that DOE should have used the levels ''the U.S. would have achieved if DOE had implemented Congress's original fuel replacement goals.''

In response, DOE believes that the commenter's assertion is incorrect on several counts. First, DOE does not have authority to mandate achievement of the goal. DOE has authority to conduct programs in accordance with the goals, to review the goals, and modify the goals. The commenter's implication that DOE could have mandated achievement of the 30 percent goal by 2010 is therefore incorrect. Second, a GHG analysis as suggested by the commenter would require the establishment of a fictitious baseline based upon a completely fabricated fuel mix that possibly could be used to meet the goal in 2010 whether or not a 2010 goal was ever achievable. Since DOE has found that the goal is unachievable, it does not know what the fuel mix would have been in 2010 if the 30 percent goal had been achieved, which is critical to determining the baseline contribution of GHGs. Without such a breakdown, no such estimate can be made.

This commenter further asserted that DOE was required to perform an environmental assessment as part of this rulemaking. As discussed below in section VII, Regulatory Review, DOE has not conducted an environmental assessment, which is consistent with the Court's holding in *Center for Biological Diversity.* (419 F. Supp 2d at 1173.)

Programmatic/DOE's Role

Three commenters and several Clean Cities-related organizations specifically called for DOE to promote programs or incentives and make recommendations to further the goals of the Replacement Fuel Programs. This Final Rule requires DOE to select a specific goal that is achievable. DOE notes that the Administration is making proposals and recommendations relevant to alternative fuel production and use. The President's 2007 State of the Union Address on January 23, 2007, made two clear and strong recommendations. Twenty in Ten proposed increasing the RFS to 35 billion gallons of renewable and alternative fuel in 2017 and giving Department of Transportation (DOT) authority to set CAFE standards for passenger vehicles based on vehicle attributes consistent with DOT's recent rule for light-duty trucks. Thus, the President's ''Twenty in Ten'' initiative contains replacement fuel and energy efficiency as its main elements, which is the same approach employed by the Replacement Fuel Goal established today.

In addition, one of the previous commenters cited CAFE standards as an opportunity for DOE to take action. As part of his Twenty in Ten initiative, the President has called for reforms in the CAFE standards. However, concerning CAFE, Congress has limited authority in this area to itself and the DOT, not DOE. While DOT does confer with DOE in this area, Congress has established the authority for CAFE regulations within DOT. (49 U.S.C. 32902).

Two commenters called for DOE to establish a replacement fuel program and develop a plan for its implementation. In addition, one of these specifically called for DOE to solicit input from stakeholders concerning measures to advance replacement fuels. In response, DOE notes that the research and development programs provided the data and development plans relied on for the analysis. As for a replacement fuel program under the context of EPAct 1992 (particularly section 502(a)), DOE has, for more than a decade, been conducting a program focused on the replacement of petroleum in the transportation sector. These on-going efforts include activities such as the Federal Fleet requirements, the State and Alternative Fuel Provider Fleets Regulations, and the Clean Cities initiative. As for soliciting input from stakeholders, the NOPR specifically provided opportunity for comment by stakeholders interested in replacement fuels, both through written comments and testimony at the hearing. In addition, DOE continues an open dialog in this area with interested stakeholders, particularly through the Clean Cities initiative.

One commenter specifically called for DOE to work with the Environmental Protection Agency (EPA) to ensure that regulations for conversions ''are not overly burdensome for those wishing to convert vehicles * * * to alternative fuels.'' DOE has a history of working with EPA in alternative fuel-related areas, and will continue to do so.

One commenter disagreed with DOE's assertion that its authority under this rulemaking is limited by EPAct 1992. It cited EPAct's section 504(c), which states that:

> If the Secretary determines that the achievement of goals described in section 502(b)(2) of this title would result in a significant and correctable failure to meet the program goals described in section 502(a) of this title, the Secretary shall issue such additional regulations as are necessary to remedy such failure.

(42 U.S.C. 13254(c)).

DOE has read this clause to mean that, if the numerical Replacement Fuel Goal (30 percent in 2010 from 502(b)(2)) conflicts with the overall replacement fuel program goal of replacing motor fuels to the maximum extent practical (from 502(a)), then DOE has additional regulatory authority to rectify the conflict. However, DOE's additional authority to establish regulations under EPAct 1992 is limited. Section 504(c) continues:

> The Secretary shall have no authority under this Act to mandate the production of alternative fueled vehicles or to specify, as applicable, the models, lines, or types of, or marketing or pricing practices, policies, or strategies for, vehicles subject to this Act. Nothing in this Act shall be construed to give the Secretary authority to mandate marketing or pricing practices, policies, or strategies for alternative fuels or to mandate the production or delivery of such fuels.

(42 U.S.C. 13254(c)).

Finally, several Clean Cities related organizations called for DOE generally to enforce EPAct, support mandated fleets with funding, increase funding to Clean Cities coalitions, and to ''propose real solutions.'' An additional commenter also raised the issue of funding for relevant programs. In response, DOE asserts that it is indeed enforcing EPAct fleet programs, through programs focused specifically on regulated fleets under titles III and V of EPAct. These programs, as mentioned

above, have been highly successful at accomplishing their missions within the context of the scope and authority provided by Congress. DOE remains committed to Clean Cities as a key element of its replacement fuel efforts. DOE intends to continue to utilize Clean Cities to identify new opportunities for success in the implementation of replacement fuel and energy efficiency technologies as they become available for deployment. As for the non-specific request that DOE propose ''real solutions,'' DOE has provided its detailed analysis supporting its decision concerning modification of the Replacement Fuel Goal, which also incorporates the technology development plans of many of its research and development programs.

C. Assessment of Comments

There are several important observations that can be made about the comments received. First, no commenter supplied any data to dispute DOE's analysis. Commenters did discuss the potential of particular technologies, but data from which DOE could make projections of the technology impacts was not provided, nor were any indications that modifying the analysis as generally proposed by several commenters would result in any significant net changes to the results of DOE's analysis. Second, a number of commenters (especially the Clean Cities and related organizations) merely asserted an objection to delaying the goal by 20 years, without any comment on the achievability of the proposed goal or an alternative goal. Third, many commenters did not appear to fully understand the purpose of the goal and the purpose of this rulemaking. As indicated in the NOPR and in the discussion above, DOE is directed by statute to analyze the existing goal of 30 percent replacement in 2010, and if found not to be achievable, modify the goal. However, many commenters discussed issues beyond the scope of this rulemaking, e.g., funding policies, establishment of particular programs, and other wide-ranging regulatory actions.

In conclusion, the comments received have not persuaded DOE that it erred in its analysis or in its choice of revised goal, as included in the NOPR. DOE does note its continuing responsibility to periodically conduct analyses of the progress toward this goal, and to modify the goal again if and when appropriate. Such modification could include proposing either earlier or later achievement, or also a higher or lower replacement fuel level.

IV. Determination That Congressional Goals Are Unachievable

DOE has determined that the 2000 goal was not achieved and that the 2010 goal is not achievable. DOE notes that it is unaware of any analysis or technical data that was used by Congress in 1992 as a basis for setting the 10 percent and 30 percent Replacement Fuel Goals set forth in EPAct 1992. DOE is also not aware of any affirmative determination by Congress or by any agency that, at the time they were set, the statutory goals were reasonably achievable.

As indicated in the NOPR, the actual data reported for 2000 indicated that the 10 percent Replacement Fuel Goal was not achieved. Replacement fuel use in that year totaled about 4.7 billion gallons, or only about 2.9 percent of the 162 billion gallons of motor fuel consumed. Of this amount, oxygenates in the form of ethanol and Methyl Tertiary Butyl Ether (MTBE) supplied about 92 percent of the replacement fuel production. (See Transportation Energy Data Book—26th Edit., Table 2.3 (2006) (replacement fuel use) and FHWA Motor Fuel Use Report, Table MF–21; *http://199.79.179.101/ohim/hs00/mf.htm.*)

Based on EIA's AER 2005 (the last such review completed prior to this final rule), replacement fuels supply approximately 2.5 percent of the total motor vehicle fuel used in motor vehicles. The amount of replacement fuel used, as a percent of total motor fuel consumed, has essentially been flat for the past decade despite some increased use of alternative and replacement motor fuels. There are two reasons for this trend. First, as discussed in the NOPR, the recently accelerated phase-out of MTBE as an additive in gasoline has limited the total amount of replacement fuels consumed since MTBE previously accounted for a significant portion of these fuels. Because a gallon of MTBE contains more energy than a gallon of ethanol, replacing MTBE with ethanol may result in more gallons of ethanol used, but not in a higher replacement fuel level, since the level of replacement (percentage) is calculated on an energy content basis. This replacement of MTBE with ethanol partly explains why replacement fuels have not garnered a larger share of the on-road fuels market on an energy basis, even as ethanol use has increased quite significantly in the past several years, increasing from a level of slightly more than 1 billion gallons in 2002 to 4 billion gallons in 2005. (AER 2005.) Second, the comparatively small growth in total replacement fuels production and use has been matched by the growth in petroleum-based motor fuel use.

The EIA AEO 2007 reference case projected that replacement fuels in 2010 will account for approximately 4.5 percent of total motor fuel use, or approximately 8.7 billion gallons of gasoline equivalent replacement fuel (although it is possible higher oil prices and the President's recent proposals will result in greater use of biofuels during this period). Given the short-term nature of the 2010 goal, it appears that ethanol would be the primary replacement fuel option to consider. Some production capacity for ethanol now exists, with increases in capacity projected over the next few years. The changes in distribution and infrastructure needed for other fuels (e.g., gaseous fuels or electricity) to make major contributions would be much longer term in nature, and thus largely impractical for serious consideration before 2010. Therefore, ethanol in blends are expected to account for about 85 percent of the replacement fuels produced in 2010, with the remaining balance made up of mostly natural gas and propane.

DOE did not receive any data or information from commenters as to the projected production capacities of replacement fuel by 2010. In addition, the commenters did not provide any data or information to indicate how the replacement fuel production capacity of 30 percent in 2010 could be achievable. DOE therefore determines that the EPAct 1992 Replacement Fuel Goal of 10 percent for 2000 was not met and that the goal of 30 percent for 2010 is not achievable, considering all information available and the economic and technical feasibility of achieving the 2010 goal.

V. Goal Modification Analysis

As part of its preparation for the NOPR, DOE conducted an analysis focused on projecting potential production capacity for replacement fuels through 2030. This was necessary to determine how the Replacement Fuel Goal should be modified. DOE has relied upon this analysis and other more recent information and data currently available in the development of this final rule. DOE has identified and reviewed relevant internal and external reports, studies, and analyses on alternative and replacement fuel use and projected production. The pertinent information was compiled to assist in the development of an ''achievable goal.''

Because of the detailed analytical description provided in the NOPR concerning this analysis, and because

today's notice relies on substantially similar analytical framework (e.g., building blocks and scenarios, and assumptions), a discussion of the analysis conducted by DOE will primarily be provided in summary form here. For more detail on the analysis, consult section V. of the NOPR. 71 FR 54776. During the period since the publication of the NOPR, EIA released portions of the AEO 2007. In order to meet the court ordered deadline and because the full AEO 2007 is unavailable, DOE could not update all of its analysis described in the NOPR. DOE does provide a comparison of the results using AEO 2006 and the available portions of AEO 2007 at the end of this section.

A. Approach

As discussed previously, DOE has two statutory criteria for modification of the Replacement Fuel Goal. First, the goal has to be aggressive enough to meet the intent of the program goal to promote replacement fuels to the ''maximum extent practicable.'' (42 U.S.C. 13252(a)). Secondly, the Replacement Fuel Goal has to be ''achievable.'' (42 U.S.C. 13254(b)).

In meeting these criteria, DOE had several options in modifying the Replacement Fuel Goal, in accordance with the authority provided in section 504 of EPAct 1992. First, DOE could modify the goal level to what it believed was achievable in the 2010 timeframe, probably around the 4.5 percent projected in the AEO 2007. Second, DOE could move the goal out in time, since the potential contributions from replacement fuels increase over time. A third option would be to combine the two primary options and modify both the replacement fuel level and date. In analyzing the data, DOE looked at all of these options. DOE's evaluated credible data, projections, and other information covering approximately the next 25 years, to see what could be achievable. DOE's evaluation and analysis went out to 2030, since that is the last date for which credible input existed, particularly in the form of data from AEO 2006 and the recently released portions of AEO 2007.

In general, the analytical framework included only existing statutory authorities and incentives in the development of the technologies. The only exception was in hydrogen and fuel cell technologies which did consider some level of additional or new incentives and/or mandates in the future. Therefore, the primary variables in DOE's analysis were projected technological and cost improvements. Hydrogen and fuel cell technologies were specifically identified as an exception because DOE recognizes that the hydrogen economy will require additional support later in the market introduction phase. Most of the other replacement fuels and technologies are viable in the market or they are getting or have gotten tax breaks, subsidies, or other price supports until they become viable in the market.

One commenter claimed that DOE's analysis assumes continued support in terms of tax credits and other incentives that are currently provided but are scheduled to expire before 2030. In response, DOE believes it was careful to keep such variations to a minimum. Most of the technologies did not assume continue price support or other incentives. The projected results from technology programs were primarily based upon reaching technology cost goals that would result in cost competitiveness without subsidies. Therefore, DOE did not assume any new policies for nearly all technologies. The only exception, as indicated above, was hydrogen and fuel cell technologies, which embedded a higher level of support into its GPRA projections.

B. Building Blocks

The Replacement Fuel Goal proposed in this action was developed after careful consideration of existing market factors, energy forecasts, and programs directed by DOE and its national laboratories. Three combined building blocks were considered: (1) The reference case projected by EIA in the AEO 2006 with updates from AEO 2007; (2) the high price case presented in the AEO 2006; and (3) projections from the DOE programs conducting research and development on replacement fuel and vehicle technologies. The outcome of this effort is several different cases under which varying levels of replacement fuel are potentially achieved.

These building blocks include replacement fuel and vehicle technologies, with projected contributions based on either the high or reference prices from the AEO, or the DOE program development projections. Some of the building blocks are relevant to all of the scenarios, while others appear in a limited number of scenarios. As indicated above, DOE evaluated data out through 2030, at periodical intervals. In all cases, the highest levels of replacement fuels appear in 2030. Below is a description of the building blocks and ''cases'' which were used to develop the four scenarios, described in the subsequent section.

AEO Reference Case Description

The AEO reference case is the base case prepared by EIA. It takes into account developments that are likely to occur as a result of policies that existed at the time the forecast was developed. AEO takes into account expected improvements and cost reductions in many technologies, but does not attempt to project the impact of DOE technology development programs. It does not account for potentially new policies, or legislation. The reference case also includes a number of other critical assumptions including economic growth rates and oil prices. The AEO 2006 reference case assumes a U.S. economic growth rate of 3 percent per year. Oil prices in this case are projected to fluctuate from the high $40 range to mid $50 range and peak at $57 in 2030 under AEO 2006. AEO 2006, which was first released in late 2005, indicates that the oil price projection in the reference case represents EIA's ''current judgment regarding the expected behavior of the Organization of Petroleum Exporting Countries (OPEC) producers in the long term, adjusting production to keep world oil prices in a range of $40 to $50 per barrel''. (AEO 2006, p. 206.)

In the AEO 2007 Reference Case update, EIA estimated that ''the average world crude oil price declines slowly in real terms (2005 dollars), from a 2006 average of more than $69 per barrel * * * to just under $50 per barrel * * * in 2014 as new supplies enter the market, then rises slowly to about $59 per barrel * * * in 2030.'' Thus the 2030 world oil price in the AEO 2007 reference case is slightly above the 2030 price in the AEO 2006 reference case ($59 versus $57). It should be noted that EIA specifically used the same rationale in developing its projections in the AEO 2007 as it had in the AEO 2006, indicating the following:

> The world oil price in AEO2007 is defined as the average price of low-sulfur, light crude oil imported into the United States—the same definition used in AEO2006. This price is approximately equal to the price of the light, sweet crude oil contract traded on the New York Mercantile Exchange (NYMEX) and the price of West Texas Intermediate (WTI) crude oil delivered to Cushing, Oklahoma. The weighted average U.S. refiners' acquisition cost of imported crude oil is $5 to $8 per barrel less than the price of imported low-sulfur, light crude oil.

(AEO 2007.) For more information on the AEO 2007 (Early Release), see *http://www.eia.doe.gov./oiaf/aeo/index.html.*

AEO High Price Case Description

The high price case makes ''more pessimistic assumptions for worldwide

crude oil and natural gas resources than in the reference case'' (AEO 2006, p. 204). In particular, OPEC resources and production capacity are projected to be lower in this case. As a result, oil prices rise to nearly $90/barrel by 2030. Even in the high price case, however, some of the projected prices are lower than recent levels, rising to $70/barrel in 2013 and $80/barrel in 2018. The high oil price forecast for the next several years ranges from $50 to $60, roughly comparable to today's prices. In this case, transportation energy demand also is reduced because of high petroleum prices, which tend to encourage fuel efficiency. At the same time, higher oil prices in general also encourage more replacement fuel use. It should be noted that at the time of preparation of this final rule, EIA had not yet released its updated High price case for the AEO 2007.

DOE Program Development Case Description

Section 504(b) of EPAct 1992 requires that the goal, as modified, be achievable. (42 U.S.C. 13254(b)) As part of the determination as to whether a goal would be achievable, DOE considered technologies that are technically and economically feasible today. DOE also considered technologies that currently may not be technologically or economically feasible, but that may be reasonably expected to be technologically and economically feasible given the achievement of certain conditions in the timeframes necessary to contribute to the goal. Many of these technologies are currently being developed under DOE's own programs.

The DOE program development case represents the estimated potential replacement fuel levels achieved if industry commercializes in significant amounts the new technologies and new fuels being developed by DOE and its industry partners through research and development programs. These estimated levels are predicated on continuing existing research and development activities and the achievement of technology goals/milestones that have been set. They also depend on economic targets being achieved and market acceptance of the technologies and fuels reviewed; however, for the most part, they do not rely upon new policy or regulatory initiatives. Information to support these cases came primarily from the relevant EERE and Fossil Energy programs, and included GPRA (Public Law 103–62; August 3, 1993) analyses and recently released technical reports identifying potential contributions of various fuel and vehicle technologies. (For more information concerning GPRA analyses, see *http://www1.eere.doe.gov/ba/pba/gpra_estimates/fy_07.html.*)

The technologies and fuels for which information was received from DOE program offices include fuel efficiency measures, ethanol, gas-to-liquid fuels, hydrogen, and electricity in PHEVs. The GPRA analysis was specifically relied on for the figures used for the Hydrogen Program and the fuel-efficiency savings rates projected for technologies arising from the EERE's FCVT Program. It should be noted that the GPRA figures are based on the AEO 2005 forecast and not AEO 2006 or AEO 2007 because AEO 2006 and AEO 2007 were not available when the most recent GPRA analysis was conducted. The GPRA analyses are updated every 2 or 3 years and have not been updated since the publication of the NOPR. In the case of hydrogen, therefore, this means that the analysis presented here is based on AEO 2007. In the case of energy efficient vehicle technology savings, DOE calculated a savings rate based on the 2007 GPRA report and applied this figure to AEO 2006's (or for the updated Reference Case analysis for AEO 2007's) projection of on-road motor fuel use.

The analysis conducted by DOE addressed a number of programs and fuels that contribute to the Replacement Fuel Goal, including energy efficiency measures, ethanol, biodiesel, coal-to-liquid fuels, gas-to-liquid fuels, hydrogen, and other alternative fuels. These programs and fuels were described in section V. of the NOPR. 71 FR 54776.

C. Replacement Fuel Scenarios

The previous section summarized the building blocks reviewed by DOE. This section describes how the various building blocks are combined into separate and distinct scenarios. Four scenarios were considered: (1) The reference case projected by EIA in AEO 2006; (2) the high price scenario presented in AEO 2006; (3) a combination of the AEO 2006 reference case with achievement of program goals (designated as program developments); and (4) a combination of the AEO 2006 high price case with program developments. The different scenarios represent the potential bounds for proposing a revised replacement fuel production goal under sections 502 and 504 of EPAct 1992. The analysis performed looked at values for replacement fuel penetrations in the 2020, 2025, and 2030 timeframes. Near the end of this section, a comparison of the reference case analyses based upon the AEO 2006 and AEO 2007 is provided.

Reference Case Scenario

As discussed earlier, the reference case represents the base case, or the most conservative approach to projecting potential replacement fuel production. The total projected replacement fuel production level by the year 2030 is approximately 8.65 percent in this scenario based upon AEO 2006. This level of petroleum replacement further assumes that all CTL fuel is used for transportation purposes. Aside from this assumption, the most noticeable difference between this scenario and the ones that include the program development case is the relatively low amount of biofuels that is projected to be used. (This is due to assumptions made about technological progress of ethanol production technologies in the program development case.) Results for this scenario are provided in Figure 1.

FIGURE 1.—SUMMARY OF RESULTS FOR REFERENCE CASE SCENARIO

Reference	2020	2025	2030
On-road Fuel Use [3]	14.42	15.36	16.46
Additional Fuel Efficiency Savings (FCVT)	0.00	0.00	0.00
OnRoad Fuel Use w/Additional Fuel Efficiency Savings	14.42	15.36	16.46
Ethanol	0.49	0.51	0.51
Biodiesel	0.02	0.02	0.02
Hydrogen/FCVs	0.001	0.001	0.002
Coal to Liquids	0.23	0.58	0.76

[3] On all summary results tables, the AEO 2006 cases have some fuel efficiency savings built into the forecasts, as a result of gradual improvements in vehicle technologies. The fuel efficiency savings reflected in the line below in each table represent those additional savings due to FCVT program developments.

FIGURE 1.—SUMMARY OF RESULTS FOR REFERENCE CASE SCENARIO—Continued

Reference	2020	2025	2030
Gas to Liquids	0.00	0.00	0.00
Other Alternative Fuels	0.10	0.11	0.12
Petroleum Use	13.58	14.14	15.03
Total Replacement Fuel	0.84	1.22	1.42
Portion Replacement Fuel	5.83%	7.95%	8.65%

[**Note:** Results in million barrels per day (mbpd) unless otherwise noted]

High Price Case Scenario

The high price case, which predicts higher oil prices throughout the forecast, indicates a potential for replacement fuel production level that is double that in the reference case. By 2030, replacement fuel production potentially accounts for 2.65 million petroleum equivalent barrels per day, providing a replacement fuel production level of 17.84 percent. The most notable changes in this forecast are the reduction in total motor fuel consumption, dropping from 16.46 to 14.86 million barrels a day as a result of reduced demand, and the significant increase in potential CTL production, which increases from a level of 0.76 million barrels a day in the reference case to 1.69 million barrels a day in the high price case. Results for this scenario are provided in Figure 2.

FIGURE 2.—SUMMARY OF RESULTS FOR HIGH PRICE CASE SCENARIO

High price	2020	2025	2030
On-road Fuel Use	13.20	13.97	14.86
Additional Fuel Efficiency Savings (FCVT)	0.00	0.00	0.00
OnRoad Fuel Use w/Additional Fuel Efficiency Savings	13.20	13.97	14.86
Ethanol	0.54	0.60	0.62
Biodiesel	0.03	0.03	0.03
Hydrogen/FCVs	0.001	0.001	0.002
Coal to Liquids	0.29	0.81	1.69
Gas to Liquids	0.04	0.19	0.19
Other Alternative Fuels	0.09	0.10	0.11
Petroleum Use	12.21	12.24	12.21
Total Replacement Fuel	0.99	1.73	2.65
Portion Replacement Fuel	7.49%	12.37%	17.84%

(**Note:** Results in mbpd unless otherwise noted).

Reference Case With Program Developments Scenario

This scenario combined the reference case assumptions regarding transportation energy demand with projections for successful DOE research and development programs. As in the reference case discussed above, this case assumes that all the CTL production capacity forecasted in the reference case is used for transportation purposes. The reference case with program developments further assumes additional fuel efficiency savings over and above those included in the reference case based on the fuel efficiency improvements and change in vehicle penetration rates attributed to commercialization of technologies undergoing research and development at DOE. Each of the other program initiatives discussed in this notice are factored into this scenario so that estimates for replacement fuel production potential of GTL, ethanol, biodiesel, and hydrogen are included. The potential impact of combining these forecasts with the individual program goals results in a replacement fuel production level potential of 35.25 percent in 2030. The most significant differences from the two previous forecasts (reference and high price stand-alone) are the incorporation of additional efficiency savings and significant biofuels (ethanol and biodiesel) production. The additional fuel efficiency improvements represent over 3 mbpd savings by 2030. The two biofuels also combine to replace more than 3 mbpd equivalent in this scenario. Results for this scenario are provided in Figure 3.

FIGURE 3.—SUMMARY OF RESULTS FOR REFERENCE CASE WITH PROGRAM DEVELOPMENT SCENARIO

Reference/program goals	2020	2025	2030
On-road Fuel Use	14.42	15.36	16.46
Additional Fuel Efficiency Savings (FCVT)	0.55	1.11	3.04
OnRoad Fuel Use w/ Additional Fuel Efficiency Savings	13.88	14.25	13.42
Ethanol	1.33	1.95	2.58
Biodiesel	0.37	0.51	0.65
Hydrogen/FCVs	0.001	0.16	0.47
Coal to Liquids	0.23	0.58	0.76
Gas to Liquids	0.05	0.15	0.15

FIGURE 3.—SUMMARY OF RESULTS FOR REFERENCE CASE WITH PROGRAM DEVELOPMENT SCENARIO—Continued

Reference/program goals	2020	2025	2030
Other Alternative Fuels	0.10	0.11	0.12
Petroleum Use	11.81	10.79	8.64
Total Replacement Fuel	2.07	3.46	4.73
Portion Replacement Fuel	14.94%	24.27%	35.25%

(**Note:** Results in mbpd unless otherwise noted).

High Price Case With Program Developments

This scenario combines the high price case assumptions with the program developments. It includes the same assumptions regarding CTL use as discussed above. The program development assumptions regarding potential replacement fuels and fuel efficiency savings are the same as used in the previous scenario. The major difference in this scenario is that CTL production more than doubles due to higher oil prices. Ethanol and biodiesel again demonstrate the potential to replace a significant amount of petroleum. The higher oil prices, however, have the effect of reducing overall motor fuel use, which magnifies the potential replacement fuel levels. The result in this scenario is a maximum potential replacement fuel level of 47.06 percent. Results for this scenario are provided in Figure 4.

FIGURE 4.—SUMMARY OF RESULTS FOR HIGH PRICE CASE WITH PROGRAM DEVELOPMENT SCENARIO

High price/program goals	2020	2025	2030
On-Road Fuel Use	13.20	13.97	14.86
Additional Fuel Efficiency Savings (FCVT)	0.50	1.01	2.74
On-Road Fuel Use w/Additional Fuel Efficiency Savings	12.70	12.96	12.12
Ethanol	1.33	1.95	2.58
Biodiesel	0.37	0.51	0.65
Hydrogen/FCVs	0.001	0.16	0.47
Coal to Liquids	0.29	0.81	1.69
Gas to Liquids	0.05	0.15	0.20
Other Alternative Fuels	0.09	0.10	0.11
Petroleum Use	10.58	9.28	6.41
Total Replacement Fuel	2.12	3.68	5.70
Portion Replacement Fuel	16.710%	28.400%	47.060%

Note: Results in mbpd unless otherwise noted.

D. DOE's VISION Model Analysis

To validate the results of its analysis, DOE used the VISION model to look at what the vehicle mix would have to be for the replacement fuel production levels suggested by the different scenarios considered. The Replacement Fuel Goal is a production capacity goal not a fuel use goal. However, production capacity (supply) is tightly linked with fuel usage (demand). The primary purpose of the VISION modeling exercise was to verify the replacement fuel production levels were reasonable given various potential vehicle mixes and fuel availability. The secondary use was to project the greenhouse emission impacts under each of the scenarios. (For more information on VISION, see *http://www.transportation.anl.gov/software/VISION/index.html.*)

The VISION model results matched very closely with those from the analysis for this rule. In most cases the VISION model projected slightly higher replacement fuel levels due to differences in assumptions about overall petroleum consumption, efficiency gains, and heating values for fuels. The projected emission results indicated that the annual emissions will decrease from approximately 846 million metric tons of carbon equivalent (MMTCe) for the AEO 2006 reference case scenario, to just under approximately 500 MMTCe for the AEO 2006 reference case with program development scenario. Additional results and discussion on the VISION results for vehicle mix and greenhouse emissions impact can be found in section V.D. of the NOPR. 71 FR 54783.

One commenter pointed out apparent discrepancies between the EIA and VISION model analyses concerning the makeup of the LDV market. While DOE acknowledges that these two analyses differ somewhat in their pathways, they are in relative agreement on the overall destination points. Comparison of the VISION model with the combined scenarios validates that the combination of replacement fuels analyzed by DOE, is achievable under the framework of this rule.

E. AEO 2007 Results

DOE utilized AEO 2006 in conducting the analysis for the NOPR. In December 2006, EIA began to make available portions of its AEO 2007. (See *http://www.eia.doe.gov/oiaf/aeo/index.html.*) EIA released its reference case update, which allowed DOE to conduct comparative analysis of its Replacement Fuel Goal analysis, namely the two scenarios based specifically upon the reference case. At the time of preparation of this final rule, EIA had not yet released its high price case, thus DOE could not update all four scenarios.

Overall, the AEO 2007 update did result in a few differences in the Replacement Fuel Goal analysis, although overall (net) impacts were relatively minor. Figure 5 below shows a comparison of the year 2030 results for the reference case scenario and the reference case with program developments scenario (portrayed in the table as ''Reference/Program Goals'').

FIGURE 5.—SUMMARY OF RESULTS FOR REFERENCE CASE AND REFERENCE CASE WITH PROGRAM DEVELOPMENT SCENARIOS FOR 2030

AEO	Reference case	Reference case	Reference/ program goals	Reference/ program goals
	2006	2007	2006	2007
On-Road Fuel Use	16.46	16.27	16.46	16.27
Additional Fuel Efficiency Savings (FCVT)	0.00	0.00	3.04	3.01
On-Road Fuel Use w/Additional Fuel Efficiency Savings	16.46	16.27	13.42	13.26
Ethanol	0.51	0.62	2.58	2.58
Biodiesel	0.02	0.03	0.65	0.65
Hydrogen/FCVs	0.002	0.002	0.47	0.47
Coal to Liquids	0.76	0.44	0.76	0.44
Gas to Liquids	0.00	0.00	0.15	0.15
Other Alternative Fuels	0.12	0.11	0.12	0.11
Petroleum Use	15.03	15.07	8.64	8.87
Total Replacement Fuel	1.42	1.20	4.73	4.39
Portion Replacement Fuel	8.65%	7.38%	35.25%	33.13%

(**Note:** Results in mbpd unless otherwise noted.)

The first change seen from the AEO 2007 reference case update is that motor fuel use drops from 16.46 to 16.27 mbpd. As for the replacement fuels, ethanol and biodiesel increase slightly, while CTL drops significantly. This change in the biofuels reflects EIA's readjusting for the RFS and the accompanying increased use of blends. EIA has indicated that the primary cause for the change to the CTL projection is higher capital costs. Discussions with industry indicated that the capital costs for CTL facilities were higher than originally anticipated, resulting in less facilities being built. Other alternative fuels are relatively flat however, and within this number electricity actually grows by nearly 40 percent over the AEO 2006 with a corresponding reduction in liquid petroleum gas. Overall these figures are very small and the changes are a reflection of minor adjustments in EIA's earlier assumptions. AEI also indicated that PHEVs were incorporated in their modeling analysis but that the resulting electricity use was negligible. The overall impact on the reference case replacement fuel percentage is to reduce the replacement fuel contribution from 8.65 percent down to 7.38 percent, a change of approximately 1.3 percentage points or 15 percent.

The impact of the 2007 AEO reference case update has much less overall significance to the reference case plus program developments scenario. This is because the efficiency contribution and many of the replacement fuel contributions in this scenario were the result of programmatic inputs, such as from GPRA or other technical analyses conducted by DOE's research and development programs. These did not change, as new analyses have not been conducted by the programs since publication of the NOPR. The programmatic inputs include additional fuel efficiency savings (implemented solely as an unchanging percentage of overall on-road fuel use), ethanol, biodiesel, hydrogen, and GTL. Thus, the biggest impact on this scenario came from the EIA change to its reference case projection for CTL (which was used in both the reference case and reference case plus program developments scenarios of this analysis). The resulting impact was to reduce the replacement fuel contribution under the reference case plus program developments scenario slightly from 35.25 percent to 33.13 percent, a reduction of just over 2 percentage points or 6 percent.

In summary, overall, the changes due to the use of the AEO 2007 reference case did not result in major impacts on the replacement fuel analysis as included in the NOPR. Thus, DOE did not see sufficient changes to warrant modifying the Replacement Fuel Goal as proposed in the NOPR.

F. Additional Reports

DOE also reviewed additional reports and analyses released during the period since the NOPR that are relevant to the development of the final rule. DOE notes three such reports.

In October 2006, the Council on Foreign Relations (CFR) released National Security Consequences of U.S. Oil Dependency, Report of an Independent Task Force (CFR Report). The CFR task force is chaired by John Deutsch (former director of Central Intelligence and Deputy Secretary of Defense) and James R. Schlesinger (former Secretary of Defense and the first Secretary of Energy). This report was focused on examining ''the consequences of dependence on imported energy for U.S. foreign policy.'' In doing so, it focused its attention on ''how oil consumption (or at least growth in consumption) can be reduced and why and how energy issues must become better integrated with other aspects of U.S. foreign oil policy.'' (See CFR Report p. xi.) Consistent with DOE's analysis supporting today's final rule, the Council's analysis ''concentrates on the next twenty years, a period long enough to put necessary policy measures into place but not so distant as to encounter a wider range of future geopolitical or technological uncertainties.'' (See CFR Report p. 4.) The Council then went on to emphasize many of the same technologies that DOE relies upon in today's action, such as energy efficiency, batteries, fuel cells, and biofuels. The Council also pointed out, as DOE did in the NOPR, that energy market forces are now leading to innovation by encouraging entrepreneurs to invest in new energy products and services, particularly research and development. While focusing on a different objective than today's final rule, the CFR Report relied on many assumptions and analyses that appear consistent with those employed by DOE in today's action.

In November 2006, the President's Council of Advisors on Science and Technology (PCAST) released The Energy Imperative: Technology and the Role of Emerging Companies (PCAST Report). PCAST was formed under Executive Order 13226 in September 2001 to advise the President ''on matters

involving science and technology policy.'' The PCAST Report recommendations focus on ''immediate steps that could be taken to reduce our Nation's reliance on foreign oil and to reduce atmospheric emissions from energy production and use.'' (PCAST Report cover letter.) For transportation, PCAST suggests ''steps for a major transition to biofuels and to electric or hydrogen-powered vehicles.'' (PCAST Report cover letter.) The major transportation-related recommendations focus specifically on increasing production of and demand for biofuels, as well as reviewing CAFE standards to make needed reforms and encourage non-fossil-fuel use. Thus, the PCAST report highlights two of the more important elements of DOE's replacement fuel analysis, biofuels and energy efficiency, and is also generally consistent with the President's recent State of the Union Address.

The Energy Security Leadership Council (ESLC) released Recommendations to the Nation on Reducing U.S. Oil Dependence in December 2006. ESLC is chaired by General P.X. Kelley, USMC (Ret.), the former Commandant of the Marine Corps, and Frederick W. Smith, Chairman, President, and CEO, FedEx Corporation. Other Council members include various leaders of industry as well as former Defense and Homeland Security officials and high-ranking military officers. As in today's action, the Council used the year 2030 as its focal point for analysis. Consistent with the DOE's Replacement Fuel Goal analysis, ESLC focused heavily upon improved efficiency of vehicles and increasing supply and demand of biofuels. Its corollary recommendations included suggestions relating to improving the efficiency of medium- and heavy-duty trucks (through both hybrid technologies and fuel efficiency standards) and carbon sequestration (to enable coal-to-liquids and other fuels production). Thus, the ESLC's portfolio also appears to be generally consistent with the portfolio relied upon by DOE.

Each of these reports provides interesting and thoughtful perspectives on issues that are closely related to those addressed in this final rule. While the reports do not include quantitative analyses that would either support or undercut DOE's analysis, they do use approaches that are similar to those used by DOE and they draw conclusions that appear to be generally consistent with those reached by DOE in this final rule. For example, each focused on a portfolio of options, with the greatest emphasis on energy efficiency, biofuels, and other non-petroleum fuels. They also considered 20–25 year time-frames, similar to those used by DOE.

G. Other Issues

Domestic Content

Section 502(b)(2) of EPAct 1992 directs that of the replacement fuels counted in the goal, at least half must be domestic replacement fuels. (42 U.S.C. 13252(b)(2)) The replacement fuels analyzed for today's final goal are assumed to be primarily domestic in nature. The only replacement fuels analyzed that showed potential for being imported are GTL, which represent a relatively small contribution to the overall goals. In addition, the small amount of GTL fuels included in the analysis was assumed to be based solely upon domestic resources. Ethanol imports are also assumed to be small. All biodiesel, CTL, and hydrogen are assumed to be domestic. Thus, DOE has assumed that the overwhelming majority of the replacement fuels included in its analyses will be domestic in nature. However, since the actual contribution of imports to the supply of these replacement fuels will be determined by markets, DOE intends to closely monitor the development of markets in this area. If it determines that these assumptions are not valid, it will consider whether changes in the Replacement Fuel Goal are warranted.

One commenter did indicate a concern about any assumptions that may have been made about exports of replacement fuels, and that any decision to reduce exports might constitute a major shift in trade policy. It should be remembered that the Replacement Fuel Goal is a production capacity goal. Therefore, for the purposes of the analysis, DOE was concerned with whether there would be sufficient capacity to produce a given amount of replacement fuels. A consideration of whether some portion of those fuels might ultimately be exported, if export was the opportunity that made the most sense, was outside the scope of DOE's analysis.

GHG

As part of its analysis of the replacement fuel levels considered in this Final Rule, DOE evaluated the overall GHG implications of the various scenarios. All scenarios show reduced carbon emissions over the reference case. Carbon emissions are reduced because more fuel efficient vehicles are used in these scenarios and the replacement fuels in general are less carbon intensive than petroleum motor fuels. The exception is the GHG emissions associated with CTL fuels if the carbon dioxide emitted during fuel production is not captured and sequestered. EIA indicates that there are currently no plans to sequester the carbon associated with CTL production absent new policies or requirements, so DOE has not assumed such emissions will be sequestered. Even with the increased emissions of GHG from CTL, the net effect of the replacement fuel production goal proposed in today(s notice is a substantial reduction in GHG emissions.

On a life cycle basis, replacement fuel percentages projected by the VISION model goal would achieve a reduction in GHG emissions of over 40 percent compared to the reference case. The annual emissions are projected to decrease from 846.5 million metric tons of carbon equivalent (MMTCe) from fuel mix represented by the AEO 2006 reference case scenario, to just under 500 MMTCe from the fuel mix represented by the fuel mix that most closely represents the AEO 2006 reference case with program development scenario. This projected reduction is primarily due to the high utilization of biofuels, most of which have significantly lower carbon emissions than petroleum-based fuels, especially when derived from biomass. As noted earlier, the exact carbon emissions cannot be pinpointed as the mix of fuels may ultimately be different than that projected; however, it is expected that significant reductions would occur.

The full VISION model is typically not updated until the middle of the calendar year, several months after release of all of the Annual Energy Outlook. Therefore, it was not possible to conduct a complete update to the GHG emission analysis conducted for the NOPR. A preliminary effort was made, focusing primarily upon the contribution from CTL because it was the only component of the analysis that changed significantly that could have a detrimental impact on GHG. Initial estimates indicate that GHG emissions from CTL are significantly greater than previously estimated. Additional studies since the original NOPR analysis indicated that the life-cycle GHG emissions from CTL produced was underestimated. At the same time, however, the updated analyses based upon the AEO2007 reference case indicate that the CTL contribution in the 2030 time-frame will be considerably less than estimated in the NOPR. The increase in per unit GHG emissions was of a comparable degree to the decrease in the projected contribution of CTL to the replacement fuel market. Thus, according to the most current analysis,

the net result is that there is no change in GHG emissions as compared to the estimates in the NOPR. There is still a projected 40 percent drop in GHG emissions versus the baseline reference case.

One commenter took particular issue with DOE's approach to its GHG analysis. This commenter claimed that DOE used the wrong baseline for assessing GHG emissions. The commenter indicated that DOE should have used the levels ''the U.S. would have achieved if DOE had implemented Congress's original fuel replacement goals.'' DOE disagrees with this comment.

First, as stated above, the goal established by Congress and modified today is not a mandate. DOE's authority is limited to supporting achievement of the goal, reviewing the goal, and modifying the goal. As such, the commenter's suggestion that DOE was required to implement the goals is a mischaracterization.

Second, the baseline suggested by the commenter would be based upon a hypothetical fuel mix used to meet the goal in 2010. Since DOE has found that the goal is unachievable, it does not know what the fuel mix would have been in 2010 to achieve a 30 percent level. This fuel mix is critical for determining the baseline contribution of GHGs. Without such a breakdown, no such estimate can be made.

VI. Modified Goal

A. 30 Percent by 2030

DOE is establishing a modified Replacement Fuel Goal of 30 percent by 2030. The modified Replacement Fuel Goal is based primarily on the evaluation of four scenarios across a range of probable market conditions and involves a portfolio of technology options as presented in the NOPR. The four scenarios project a replacement fuel percentage that ranges from just over 7 percent to a little above 47 percent in the 2030 timeframe. DOE selected a goal that falls near the middle of this range, providing a balance between the most optimistic and pessimistic scenarios analyzed by DOE. Based on the analysis as presented in the NOPR and summarized in this notice DOE determines that a fuel production capacity of 30 percent by 2030 is achievable.

Section 504 makes clear that achievability of the goal is key, both for analysis of the goal as well as modifying the goal. (42 U.S.C. 13245(b).) EPAct 1992, however, does not define ''achievable'' for the purpose of modifying the goal. Section 502(b)(2) directs DOE to consider the technological and economic feasibility of the statutory goal in determining the goal's achievability under the initial review (42 U.S.C. 13242(b)(2).) As stated in the NOPR, DOE has determined that in order for a goal to be achievable there must be a reasonable expectation, based on technological and economic feasibility, that the desired level of production capacity will be created within the relevant timeframe. In order to further ensure that the final goal is achievable, as discussed above, the final rule generally considered only policies and programs that are currently in place.

In establishing the Replacement Fuel Goal adopted today, DOE assumed that not all technologies would be fully adopted into the marketplace. This assumption is consistent with statements provided by one commenter, who stated that to assume that research and development programs will accomplish all of their goals is unrealistic. This assumption provides an appropriate balance between the statutory requirements of the ''maximum extent practicable'' and ''achievable.''

DOE has determined that a timeframe of 2030 is necessary to achieve the 30 percent level of the Replacement Fuel Goal adopted today. There are important reasons why a timeframe extending out to 2030 is required to make major changes in motor fuel consumption patterns and thus production levels— the lead-time for investments to begin and bear fruit, and the retirement cycles for U.S. vehicles.

Major investments of capital are required to establish industrial capacity to produce replacement fuels. Such investments are typically focused over the entire operating life of a production facility (often 30 years) and potential investors may require a high degree of certainty that the cost of competing fuels will be higher than the cost of fuels produced by the subject plant far into the future, thus allowing a positive return on investment. Barriers to such major investments include uncertainty of world oil prices, high cost of production coupled with high initial capital cost, and the long decision-to-production lead times.

Once investments are made to develop replacement fuel production, production facilities must be built. It can take five years or more from the start of construction on a new facility until full operation is achieved, depending on the complexity and size of the production facility involved. Achievement of the 30 percent Replacement Fuel Goal is projected to require a substantial number of new production facilities (such as plants to produce cellulosic ethanol and CTL fuels). Construction of production facilities is not expected to occur simultaneously, thereby resulting in an additional five or even ten years until production capacity is at a level necessary to achieve the Replacement Fuel Goal.

Many of the investments anticipated in 1992 have only recently begun. Recent high oil prices are beginning to spur more investment in alternative and replacement fuels, but not fast enough to allow DOE to set a 2010 replacement fuel production goal at levels any higher than the AEO 2007 (~4.5 percent).

Although the Replacement Fuel Goal is production (supply) based, production is closely linked to fuel usage (demand). On the vehicle side, a similar period of lead-time is typically required to make a significant impact on U.S. fuel consumption patterns. This is because it takes more than 25 years to turn over the U.S. fleet of in-use motor vehicles. According to the 25th Edition of the Transportation Energy Data Book (TEDB 25, U.S. DOE and Oak Ridge National Laboratory, ORNL–6974, 2006), after 30 years, approximately 93 percent of the 1990 model year vehicles are projected to be retired, and slightly less than 96 percent of the 1990 model year light trucks will have been scrapped. The median lifetime for 1990 cars is now 16.9 years, and 15.5 years for 1990 light trucks. While the truck numbers are relatively consistent (compared to 1970 and 1980 model years), the car numbers have increased substantially (from 11.5 years in 1970 and 12.5 years in 1980).

The effects of this can be seen by a U.S. vehicle population of 226 million in 2003, with annual new LDV sales of approximately 16.5–17 million/year (or approximately equal to 7 percent of the size of the in-use fleet). Thus, any replacement fuel or higher efficiency technology which requires actual replacement of vehicles must be phased into the U.S. fleet of vehicles over a number of years to eventually account for a significant portion of in-use vehicles. (See TEDB, Tables 3.8, 3.9, 4.5, 4.6, and 8.1.)

DOE has determined to maintain the level of the goal at 30 percent for two reasons. First, when Congress passed EPAct 1992, it indicated that it believed the level of 30 percent replacement fuel was appropriate. Second, this level of replacement fuel production is both consistent with the overall goals of the President's AEI and Twenty in Ten initiatives, to promote replacement fuels and energy efficiency.

Since DOE's analysis of the Replacement Fuel Goal was originally published in the NOPR, DOE has continued to review relevant data and published reports to inform today's decision. Overall, the reports appear to rely on an analytical framework consistent with that relied upon for today's final rule, further supporting the reasonableness of DOE's approach.

DOE also reviewed comments received in response to the NOPR and found that none included data to support a Replacement Fuel Goal other than that adopted in this final rule. It should be noted that nearly all of the public comments agreed with the need to modify the goal, but a majority disagreed with the Department's choice to move the goal to 2030. As discussed above in section III, a variety of commenters requested that DOE establish a more aggressive goal with a stronger focus upon program development and implementation. While a number of these commenters indicated that they wanted to see DOE set a ''higher goal,'' few offered concrete proposals as to what that goal should be and how it could be achieved.

DOE is required to set a goal that is deemed achievable. As illustrated in the analysis above and that provided in the NOPR, DOE has set out a rational pathway to the achievement of a goal, based upon widely accepted forecasts (such as the EIA forecast) and information provided by DOE research and development programs. In addition, the documents provided by the research and development programs and included within the docket, include the individual pathways for contributing to the achievement of the modified Replacement Fuel Goal. As for utilizing either of the ''program developments'' cases as the specific goal level, DOE explicitly rejected a goal based solely on these levels because of the fact that not all research and development programs can be expected to achieve *all* milestones. DOE is unable to set a more accelerated pathway based upon the information it has at this time.

In summary, due to both lead-times for fuel supply investments and the time required to turn over nearly all of the U.S. fleet of vehicles, a significant change in the utilization of U.S. motor fuel consumption patterns could take more than two decades. Today's decision is based primarily on the existing budgetary and policy framework. Therefore, it is largely a reflection of existing and expected conditions. In and of itself, it is not an action plan or roadmap for expanding replacement fuel production capacity. Nothing in this action precludes appropriate parties (such as Federal, State, or local governments, or private industry) from taking steps to accelerate achievement of the goal.

B. Interim Goal

As proposed, today's final rule adopts a revised the Replacement Fuel Goal for 2030. Today's rule does not adopt an interim Replacement Fuel Goal. The court order under which today's final rule is being issued, directed DOE to ''revise the *goal* for replacement fuels contained in the Energy Policy Act of 1992.'' *Center for Biological Diversity* v. *U.S. Dept. of Energy et. al.*, No. 05–cv–01526–WHA Document 54 p. 2 (N.D. Cal. March 30, 2006) (Order Re Timing of Relief); emphasis added. As indicated by the court, DOE is only required to revise a single goal, and not the final goal and the interim goal.

Several commenters urged DOE to establish a revised interim goal in conjunction with a revised final goal. Commenters stated that Congress established the ten percent by 2000 interim goal as a method of evaluating the Nation's progress in achieving the original thirty percent by 2010 final goal. Commenters further stated that a revised interim goal is necessary to provide for an evaluation of progress towards achieving the revised goal, and is necessary so that DOE may identify difficulties in achieving the revised goal earlier in the process.

A revised interim goal is not necessary for evaluating the progress in achieving the revised final goal adopted in today's final rule. The EIA AEO provides the current production capacity of alternative fuel in comparison to the consumption of motor fuel in the Untied States. The EIA AEO provides a de facto report on the progress in achieving the revised Replacement Fuel Goal. As such, DOE determined that an interim goal is not needed to monitor the progress of the Replacement Fuel Goal.

Further, DOE will periodically evaluate the prospects for achieving the Replacement Fuel Goal set in today's rule, including tracking the levels projected for intervening years, and will publish the results of its evaluations as appropriate. If the AEO projections should indicate that the goal, as revised in this action, no longer meets the criteria of achievable, or if it appears that the goal can be achieved earlier or a greater level can be achieved, DOE will institute a rulemaking process to modify the goal at that time.

VII. Regulatory Review

A. Review Under Executive Order 12866

Today's final rule action has been determined to be a ''significant regulatory action'' under Executive Order 12866, Regulatory Planning and Review, 58 FR 51735 (October 4, 1993). Accordingly, this action was subject to review under the Executive Order by the Office of Information and Regulatory Affairs in the Office of Management and Budget.

B. Review Under Regulatory Flexibility Act

The Regulatory Flexibility Act, 5 U.S.C. 601–612, requires preparation of a regulatory flexibility analysis for any rule that is likely to have a significant economic impact on a substantial number of small entities. Today's action merely modifies the Replacement Fuel goal, with no requirements imposed upon any entity. Therefore, this action will not result in compliance costs on small entities. DOE certifies that this final rule will not have a significant economic impact on a substantial number of small entities, and accordingly, no regulatory flexibility analysis has been prepared.

C. Review Under the Paperwork Reduction Act

No new record keeping requirements, subject to the Paperwork Reduction Act, 44 U.S.C. 3501, *et seq.*, are imposed by this final rule.

D. Review Under the National Environmental Policy Act of 1969 (NEPA)

DOE has not prepared an environmental impact statement (EIS) or an environmental assessment (EA) for the final rule, as neither is required. The final rule implements the March 6, 2006, Order of the U.S. District Court of California to modify the EPAct 1992 Replacement Fuel Goal. *Center for Biological Diversity*, 419 F.Supp 2d 1166. In its order, the Court determined that EPAct 1992 imposed mandatory action on the Secretary in requiring that the goal be modified, if the Secretary determines the goal is unachievable. Since DOE lacked discretion, the Court determined that NEPA did not apply. In the final rule, DOE has determined that the ''30 percent by 2010'' goal is unachievable. Therefore, modification of the goal is mandatory, and consistent with the Court's Order, neither an EA or EIS is required.

E. Review Under Executive Order 12988

With respect to the review of existing regulations and the promulgation of

new regulations, section 3(a) of Executive Order 12988, Civil Justice Reform, 61 FR 4729 (February 7, 1996), imposes on Executive agencies the general duty to adhere to the following requirements: (1) Eliminate drafting errors and ambiguity; (2) write regulations to minimize litigation; and (3) provide a clear legal standard for affected conduct rather than a general standard and promote simplification and burden reduction. With regard to the review required by sections 3(a) and 3(b) of Executive Order 12988 specifically requires that Executive agencies make every reasonable effort to ensure that the regulation: (1) Clearly specifies the preemptive effect, if any; (2) clearly specifies any effect on existing Federal law or regulation; (3) provides a clear legal standard for affected conduct while promoting simplification and burden reduction; (4) specifies the retroactive effect, if any; (5) adequately defines key terms; and (6) addresses other important issues affecting clarity and general draftsmanship under any guidelines issued by the Attorney General. Section 3(c) of Executive Order 12988 requires Executive agencies to review regulations in light of applicable standards in sections 3(a) and 3(b) to determine whether they are met or it is unreasonable to meet one or more of them. Executive Order 12988 does not apply to this rulemaking notice because DOE is merely modifying the Replacement Fuel Goal provided in section 502(b)(2) of EPAct 1992, and is not establishing any regulations that would impose any requirements on any person or entity.

F. Review Under Executive Order 13132

Executive Order 13132, Federalism, 64 FR 43255 (August 4, 1999), imposes certain requirements on agencies formulating and implementing policies or regulations that preempt State law or that have federalism implications. Agencies are required to examine the constitutional and statutory authority supporting any action that would limit the policymaking discretion of the States and carefully assess the necessity for such actions. DOE has examined today's modification of the Replacement Fuel Goal and has determined that it will not preempt State law and will not have a substantial direct effect on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.

G. Review of Impact on State Governments—Economic Impact on States

Section 1(b)(9) of Executive Order 12866, Regulatory Planning and Review, 58 FR 51735 (September 30, 1993), established the following principle for agencies to follow in rulemakings: ''Wherever feasible, agencies shall seek views of appropriate State, local, and tribal officials before imposing regulatory requirements that might significantly or uniquely affect those governmental entities. Each agency shall assess the effects of Federal regulations on State, local, and tribal governments, including specifically the availability of resources to carry out those mandates, and seek to minimize those burdens that uniquely or significantly affect such governmental entities, consistent with achieving regulatory objectives. In addition, as appropriate, agencies shall seek to harmonize Federal regulatory actions with regulated State, local and tribal regulatory and other governmental functions.''

Because DOE is modifying the Replacement Fuel Goal under section 502(b)(2) of EPAct 1992, and is not establishing any requirements, no significant impacts upon State and local governments are anticipated. The position of State fleets currently covered under the existing EPAct 1992 fleet program is unchanged by this action.

H. Review of Unfunded Mandates Reform Act of 1995

Title II of the Unfunded Mandates Reform Act of 1995, Public Law 104–4, requires each Federal agency to assess the effects of Federal regulatory actions on State, local and tribal governments and the private sector. The Act also requires a Federal agency to develop an effective process to permit timely input by elected officials on a proposed ''significant intergovernmental mandate,'' and requires an agency plan for giving notice and opportunity for timely input to potentially affected small governments before establishing any requirements that might significantly or uniquely affect small governments. On March 18, 1997, DOE published in the **Federal Register** a statement of policy on its process for intergovernmental consultation under the Act. 62 FR 12820. The final rule published today does not establish or contain any Federal mandate, so the requirements of the Unfunded Mandates Reform Act do not apply.

I. Review of Treasury and General Government Appropriations Act, 1999

Section 654 of the Treasury and General Government Appropriations Act, 1999, Public Law 105–277, requires Federal agencies to issue a Family Policymaking Assessment for any proposed rule that may affect family well-being. Today's final rule does not have any impact on the autonomy or integrity of the family as an institution. Accordingly, DOE has concluded that it is not necessary to prepare a Family Policymaking Assessment.

J. Review of Treasury and General Government Appropriations Act, 2001

The Treasury and General Government Appropriations Act, 2001 (44 U.S.C. 3516 note) provides for agencies to review most disseminations of information to the public under guidelines established by each agency pursuant to general guidelines issued by the Office of Management and Budget (OMB). OMB's guidelines were published at 67 FR 8452 (February 22, 2002), and DOE's guidelines were published at 67 FR 62446 (October 7, 2002). DOE has reviewed today's final rule under the OMB and DOE guidelines, and has concluded that it is consistent with applicable policies in those guidelines.

K. Review Under Executive Order 13175

Under Executive Order 13175, Consultation and Coordination with Indian Tribal Governments, 65 FR 67249 (November 9, 2000), DOE is required to consult with Indian tribal officials in development of regulatory policies that have tribal implications. Today's final rule does not have such implications. Accordingly, Executive Order 13175 does not apply.

L. Review Under Executive Order 13211

Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy, Supply, Distribution, or Use, 66 FR 28355 (May 22, 2001) requires preparation and submission to OMB of a Statement of Energy Effects for significant regulatory actions under Executive Order 12866 that are likely to have a significant adverse effect on the supply, distribution, or use of energy. A modification to the Replacement Fuel Goal under EPAct 1992 section 502(b)(2) does not require fleets, suppliers of energy, or distributors of energy to do or to refrain from doing anything. Consequently, DOE has concluded there is no need for a Statement of Energy Effects.

M. Congressional Notification

As required by 5 U.S.C. 801, DOE will submit to Congress a report regarding the issuance of today's Final Rule prior to the effective date set forth at the outset of this Final Rule. The report will state that it has been determined that the rule is not a ''major rule'' as defined by 5 U.S.C. 801(2).

VIII. Approval by the Office of the Secretary

The issuance of this Final Rule for the Replacement Fuel Goal modification has been approved by the Office of the Secretary.

List of Subjects in 10 CFR Part 490

Administrative practice and procedure, Energy conservation, Fuel economy, Gasoline, Motor vehicles, Natural gas, Penalties, Petroleum, Reporting, and recordkeeping requirements.

Issued in Washington, DC, on March 6, 2007.

Alexander A. Karsner,

Assistant Secretary, Energy Efficiency and Renewable Energy.

■ For the reasons set forth in the Preamble, the Department of Energy is amending Chapter II of title 10 of the Code of Federal Regulations as set forth below:

PART 490—ALTERNATIVE FUEL TRANSPORTATION PROGRAM

■ 1. The authority citation for part 490 is revised to read as follows:

Authority: 42 U.S.C. 7191 *et seq.*; 42 U.S.C. 13201, 13211, 13220, 13251 *et seq.*

■ 2. In § 490.1 of subpart A, paragraph (b) is revised to read as follows:

§ 490.1 Purpose and Scope.

* * * * *

(b) The provisions of this subpart cover:

(1) The definitions applicable throughout this part;

(2) Procedures to obtain an interpretive ruling and to petition for a generally applicable rule to amend this part; and

(3) The goal of the replacement fuel supply and demand program established under section 502(a) of the Act (42 U.S.C. 13252(a)).

■ 3. Subpart A is amended by adding § 490.8 to read as follows:

§ 490.8 Replacement fuel production goal.

The goal of the replacement fuel supply and demand program established by section 502(b)(2) of the Act (42 U.S.C. 13252(b)(2)) and revised by DOE pursuant to section 504(b) of the Act (42 U.S.C. 13254(b)) is to achieve a production capacity of replacement fuels sufficient to replace, on an energy equivalent basis, at least 30 percent of motor fuel consumption in the United States by the year 2030.

[FR Doc. E7–4324 Filed 3–14–07; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2007–27267; Directorate Identifier 2002–NE–40–AD; Amendment 39–14991; AD 2007–06–10]

RIN 2120–AA64

Airworthiness Directives; Rolls-Royce plc RB211–524 Series Turbofan Engines

AGENCY: Federal Aviation Administration (FAA), Department of Transportation (DOT).

ACTION: Final rule.

SUMMARY: The FAA is superseding an existing airworthiness directive (AD) for Rolls Royce plc (RR) RB211–524 series turbofan engines with certain part number (P/N) intermediate pressure compressor (IPC) stage 5 disks installed. That AD currently requires new reduced IPC stage 5 disk cyclic limits. This AD requires the same reduced IPC stage 5 disk cyclic limits, requires removal from service of affected disks that already exceed the new reduced cyclic limit, and, removal from service of other affected disks before exceeding their cyclic limits using a drawdown schedule. This AD also exempts disks reworked to RR Service Bulletin (SB) No. RB.211–72–E182, Revision 1, dated July 30, 2004, and allows an on-wing eddy current inspection (ECI) on RB211–524G and RB211–524H series engines. This AD results from the manufacturer issuing a revised Alert Service Bulletin (ASB) to remove certain disks from applicability, and to allow an on-wing ECI on RB211–524G and RB211–524H series engines. We are issuing this AD to prevent failure of the IPC stage 5 disk, which could result in uncontained engine failure and possible damage to the airplane.

DATES: This AD becomes effective April 19, 2007. The Director of the Federal Register approved the incorporation by reference of certain publications listed in the regulations as of April 19, 2007.

ADDRESSES: You can get the service information identified in this AD from Rolls-Royce plc, P.O. Box 31 Derby, DE248BJ, United Kingdom; telephone 011–44–1332–242424; fax 011–44–1332–249936.

You may examine the AD docket on the Internet at *http://dms.dot.gov* or in Room PL–401 on the plaza level of the Nassif Building, 400 Seventh Street, SW., Washington, DC.

FOR FURTHER INFORMATION CONTACT: Ian Dargin, Aerospace Engineer, Engine Certification Office, FAA, Engine and Propeller Directorate, 12 New England Executive Park, Burlington, MA 01803; telephone (781) 238–7178; fax (781) 238–7199; e-mail: *ian.dargin@faa.gov.*

SUPPLEMENTARY INFORMATION: The FAA proposed to amend 14 CFR part 39 with a proposed AD. The proposed AD applies to RR RB211–524 series turbofan engines with certain P/N IPC stage 5 disks installed. We published the proposed AD in the **Federal Register** on July 11, 2006 (71 FR 39025). That action proposed to require:

- Establishing new reduced IPC stage 5 disk cyclic limits.
- Removing from service affected disks that already exceed the new reduced cyclic limit.
- Removing from service other affected disks before exceeding their cyclic limits, using a drawdown schedule.
- Allowing optional inspections at each shop visit or an on-wing ECI to extend the disk life beyond the specified life.

Examining the AD Docket

You may examine the docket that contains the AD, any comments received, and any final disposition in person at the Docket Management Facility between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The Docket Office (telephone (800) 647–5227) is located on the plaza level of the Department of Transportation Nassif Building at the street address stated in **ADDRESSES**. Comments will be available in the AD docket shortly after the DMS receives them.

Comments

We provided the public the opportunity to participate in the development of this AD. We have considered the comments received.

Request To Add a Note

One commenter, Rolls-Royce plc, requests that we add a note, just above compliance paragraph (j)(5), that states: ''To qualify for maximum alleviation since last NDT inspection (see Table 5 of this AD) it is recommended that discs be ECI inspected using paragraph 3.D. of the Accomplishment Instructions of RR

Alert Service Bulletin No. RB.211–72–AD428, Revision 5, dated March 18, 2005.'' The commenter feels that this note adds clarification to the AD compliance. We do not agree. The note is identified in the service bulletin that is incorporated by reference, and need not be included in the text of the AD. We did not change the AD.

Request To Add Engine Series

Rolls-Royce plc requests that we add the RB211–524B/B3 engine series to compliance paragraph (k)(1), and add the RB211–524H2 and RB211–524H2–T engine series to compliance paragraph (k)(2), as they need to be included, the same as they appear in the service bulletin. We agree and added those engine series to the paragraphs.

Clarification of Paragraph (g)

Since we issued the proposed AD, we reviewed the wording in paragraph (g) and realized that the compliance times in that paragraph were in conflict. We clarified that paragraph. It now states to comply with the reduced cyclic life limits in Table 3 of this AD within 30 days after the effective date of this AD, or conduct optional qualifying nondestructive test (NDT) inspections before December 1, 2008, to extend the IPC stage 5 disk life as specified in paragraph (i) of this AD.

Conclusion

We have carefully reviewed the available data, including the comments received, and determined that air safety and the public interest require adopting the AD with the changes described previously. We have determined that these changes will neither increase the economic burden on any operator nor increase the scope of the AD.

Docket Number Change

We are transferring the docket for this AD to the Docket Management System as part of our on-going docket management consolidation efforts. The new Docket No. is FAA–2007–27267. The old Docket No. became the Directorate Identifier, which is 2002–NE–40–AD. This AD might get logged into the DMS docket, ahead of the previously collected documents from the old docket file, as we are in the process of sending those items to the DMS.

Costs of Compliance

We estimate this AD will not affect any engines installed on airplanes of U.S. registry. Based on this, we estimate this AD will not have any cost to U.S. operators.

Authority for This Rulemaking

Title 49 of the United States Code specifies the FAA's authority to issue rules on aviation safety. Subtitle I, Section 106, describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes in more detail the scope of the Agency's authority.

We are issuing this rulemaking under the authority described in Subtitle VII, Part A, Subpart III, Section 44701, ''General requirements.'' Under that section, Congress charges the FAA with promoting safe flight of civil aircraft in air commerce by prescribing regulations for practices, methods, and procedures the Administrator finds necessary for safety in air commerce. This regulation is within the scope of that authority because it addresses an unsafe condition that is likely to exist or develop on products identified in this rulemaking action.

Regulatory Findings

We have determined that this AD will not have federalism implications under Executive Order 13132. This AD will not have a substantial direct effect on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.

For the reasons discussed above, I certify that this AD:

(1) Is not a ''significant regulatory action'' under Executive Order 12866;

(2) Is not a ''significant rule'' under DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and

(3) Will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

We prepared a summary of the costs to comply with this AD and placed it in the AD Docket. You may get a copy of this summary at the address listed under **ADDRESSES**.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

Adoption of the Amendment

■ Accordingly, under the authority delegated to me by the Administrator, the Federal Aviation Administration amends 14 CFR part 39 as follows:

PART 39—AIRWORTHINESS DIRECTIVES

■ 1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

■ 2. The FAA amends § 39.13 by removing Amendment 39–14202 (70 FR 43036, July 26, 2005) and by adding a new airworthiness directive, Amendment 39–14991, to read as follows:

2007–06–10 Rolls-Royce plc: Amendment 39–14991. Docket No. FAA–2007–27267; Directorate Identifier 2002–NE–40–AD.

Effective Date

(a) This airworthiness directive (AD) becomes effective April 19, 2007.

Affected ADs

(b) This AD supersedes AD 2005–15–13, Amendment 39–14202.

Applicability

(c) This AD applies to the Rolls-Royce plc (RR) RB211–524 series turbofan engines listed in the following Table 1, with intermediate pressure compressor (IPC) stage 5 disk part numbers (P/Ns) listed in Table 2 of this AD, installed.

TABLE 1.—ENGINE MODELS AFFECTED

–524B–02	–524B–B–02	–524B3–02	–524B4–02	–524B4–D–02
–524B2–19	–524B2–B–19	–524C2–19	–524C2–B–19	–524D4–19
–524D4–B–19	–524D4X–19	–524D4X–B–19	–524D4–39	–524D4–B–39
–524G2–19	–524G2–T–19	–524G3–19	–524G3–T–19	–524H2–19
–524H2–T–19	–524H–36	–524H–T–36		

These engines are installed on, but not limited to, Boeing 747, 767, and Lockheed L–1011 series airplanes.

TABLE 2.—IPC STAGE 5 DISK P/NS AFFECTED

LK60130	LK65932	LK69021	LK81269	LK83282
LK83283	UL12290	UL15743	UL15744	UL15745
UL19132	UL20785	UL20832	UL23291	UL25011
UL36821	UL36977	UL36978	UL36979	UL36980
UL36981	UL36982	UL36983	UL37078	UL37079
UL37080	UL37081	UL37082	UL37083	UL37084

Unsafe Condition

(d) This AD results from the manufacturer issuing a revised Alert Service Bulletin (ASB) to remove certain disks from applicability and to allow an on-wing eddy current inspection (ECI) on RB211–524G and RB211–524H series engines. The actions specified in this AD are intended to prevent failure of the IPC stage 5 disk, which could result in uncontained engine failure and possible damage to the airplane.

Compliance

(e) You are responsible for having the actions required by this AD performed within the compliance times specified unless the actions have already been done.

Exempted Disks

(f) For engines with an IPC stage 5 disk P/N listed in Table 2 of this AD, reworked to RR SB No. RB.211–72–E182, Revision 1, dated July 30, 2004, no further action is necessary.

Cycle Limits

(g) Comply with the reduced cyclic life limits in Table 3 of this AD within 30 days after the effective date of this AD, or conduct optional qualifying nondestructive test (NDT) inspections before December 1, 2008 to extend the IPC stage 5 disk life, as specified in paragraph (i) of this AD.

TABLE 3.—CYCLIC LIFE LIMITS WITHOUT QUALIFYING NDT INSPECTION

Date of reduced life limit	Engine models			
	–524G2, G2–T, G3, G3–T, H2, H2–T, H–36, H–T–36	–524D4, D4–B, D4–B–39, D4X, D4X–B, D4–39	–524B2, B2–B, C2, C2–B	–524B–02, B–B–02, B3–02, B4–02, B4–D–02
November 30, 2002	13,500 cycles-in-service (CIS).	16,150 CIS	16,000 CIS	16,200 CIS.
April 1, 2003	13,500 CIS	13,500 CIS	13,500 CIS	14,000 CIS.
December 1, 2003	12,000 CIS	13,500 CIS	13,500 CIS	14,000 CIS.
December 1, 2004	11,000 CIS	13,500 CIS	12,000 CIS	12,000 CIS.
December 1, 2005	11,000 CIS	12,000 CIS	12,000 CIS	12,000 CIS.

(h) On December 1, 2008, the revised cyclic life limits specified in Table 4 of this AD become effective. Incorporate the revised cyclic life limits specified in Table 4 of this AD into the RR Time Limits Manual, 05–10–01.

TABLE 4.—CYCLIC LIFE LIMITS ON DECEMBER 1, 2008

Date of reduced life limit	Engine models			
	–524G2, G2–T, G3, G3–T, H2, H2–T, H–36, H–T–36	–524D4, D4–B, D4–B–39, D4X, D4X–B, D4–39	–524B2, B2–B, C2, C2–B	–524B–02, B–B–02, B3–02, B4–02, B4–D–02
December 1, 2008	7,830 CIS	8,700 CIS	8,900 CIS	9,000 CIS.

Optional Inspections

(i) Before December 1, 2008, you may perform an optional NDT inspection on-wing or at each shop visit to extend the disk life. Guidance for these inspections is provided in paragraphs (j) or (k) of this AD.

Optional Inspections at Shop Visit

(j) Perform optional inspections at shop visit, as follows:

(1) Remove corrosion protection from IPC stage 5 disk. Information on corrosion protection removal can be found in the Engine Maintenance Manual.

(2) Perform a visual inspection and a binocular inspection of the IPC stage 5 disk for corrosion pitting at the cooling air holes and defender holes in the disk front spacer arm. Follow paragraph 3.C. of the Accomplishment Instructions of RR ASB No. RB.211–72–AD428, Revision 5, dated March 18, 2005. The RR Engine Maintenance Manual, Inspection Check-00 (ATA 72–32–31–200–000), contains limits for corrosion pitting of the IPC stage 5 disk.

(3) If the disk has corrosion pitting in excess of limits, remove the disk from service.

(4) If the disk is free from corrosion pitting, perform a magnetic penetrant inspection (MPI) of the entire disk as follows:

(i) For RB211–524G2–T, RB211–524G3–T, and RB211–524H–T series engines, the RR Engine Maintenance Manual, Inspection Check 08 (ATA 72–32–31–200–008), contains limits for corrosion pitting of the IPC stage 5 disk.

(ii) For RB211–524G2, RB211–524G3, and RB211–524H series engines, the RR Engine Maintenance Manual, Inspection Check 09 (ATA 72–32–31–200–009), contains limits for corrosion pitting of the IPC stage 5 disk.

(iii) If the disk passes the MPI and you find no cracks, complete all other inspections, re-apply corrosion protection to the disk, and return the disk to service using the cyclic limits allowed by paragraph (m) of this AD. RR Repair FRS5900 contains information on re-applying corrosion protection.

(5) If the disk has corrosion pitting that is within limits, do the following:

(i) Perform an ECI on all disk cooling air holes, defender holes, and inner and outer faces. Use paragraph 3.D. of the Accomplishment Instructions of RR ASB No. RB.211–72–AD428, Revision 5, dated March 18, 2005. The RR Engine Maintenance Manual, Inspection Check-00 (ATA 72–32–31–200–000), contains limits for corrosion pitting of the IPC stage 5 disk.

(ii) If the disk passes the ECI and you find no cracks, perform an MPI on the entire disk.

(iii) If the disk passes the MPI and you find no cracks, re-apply corrosion protection to the disk, and return the disk to service using the cyclic limits allowed by paragraph (m) of this AD.

Optional On-Wing Eddy Current Inspections

(k) You may perform an optional on-wing ECI of the IPC stage 5 disk only once between shop visit inspections as follows:

(1) For RB211–524B2/C2, RB211–524B/B3, and RB211–524B4/D4 series engines, use paragraphs 3.A. through 3.F. of the Accomplishment Instructions of RR SB No. RB.211–72–E148, dated March 13, 2003, and RR SB No. RB.211–72–E150, Revision 1, dated June 4, 2003.

(2) For RB211–524G2, RB211–524G2–T, RB211–524G3, RB211–524G3–T, RB211–524H, RB211–524H–T, RB211–524H2, and RB211–524H2–T series engines, use paragraphs 3.A. through 3.M. of the Accomplishment Instructions of RR SB No. RB.211–72–E171, Revision 1, dated February 8, 2005.

(3) If the disk passes the ECI and you find no cracks, you may extend the cycle life as specified in paragraph (m) of this AD.

Definition of Shop Visit

(l) The manufacturer defines a shop visit as the separation of an engine major case flange. This definition excludes shop visits when only field maintenance type activities are performed in lieu of performing them on-wing (such as to perform an on-wing inspection of a tail engine installation on a Lockheed L–1011 series airplane).

Cyclic Life Extension

(m) Disks that pass an optional inspection may remain in service after that inspection for the additional cycles listed in the following Table 5, until the next inspection, until the cyclic life limit published in the RR Time Limits Manual, 05–10–01, is reached, or December 1, 2008, whichever occurs first.

TABLE 5.—CYCLIC LIFE EXTENSION

Type of extension	Engine models			
	–524G2, G2–T, G3, G3–T, H2, H2–T, H–36, H–T–36 (cycles)	–524D4, D4–B, D4–B–39, D4X, D4X–B, D4–39 (cycles)	–524B2, B2–B, C2, C2–B (cycles)	–524B–02, B–B–02, B3–02, B4–02, B4–D–02 (cycles)
Extension After Passing MPI	1,600	2,000	2,000	2,000
Extension After Passing In-Shop ECI	3,800	4,500	4,500	4,500
Extension After Passing On-Wing ECI	1,000	1,200	1,200	1,200

Disks That Have Been Intermixed Between Engine Models

(n) The RR Time Limits Manual, 05–00–01, contains information on intermixing disks between engine models.

Alternative Methods of Compliance

(o) The Manager, Engine Certification Office, has the authority to approve alternative methods of compliance for this AD if requested using the procedures found in 14 CFR 39.19.

Credit for Previous Inspections

(p) Inspections done using RR SB No. RB.211–72–E150, dated April 17, 2003, SB No. RB.211–72–E171, dated December 14, 2004, SB No. RB.211–72–D428, Revision 3, dated June 30, 2003, and ASB No. RB.211–72–AD428, Revision 4, dated March 7, 2005, meet the requirements of this AD.

Reporting Requirement

(q) Report findings of all inspections of the IPC stage 5 disk using paragraph 3.B.(2) of the Accomplishment Instructions of RR No. ASB RB.211–72–AD428, Revision 5, dated March 18, 2005. The Office of Management and Budget (OMB) has approved the reporting requirements specified in Paragraph 3.B. of the Accomplishment Instructions of RR No. ASB RB.211–72–AD428, Revision 5, dated March 18, 2005, and assigned OMB control number 2120–0056.

Related Information

(r) CAA airworthiness directive G–2005–0008, dated March 8, 2005, also addresses the subject of this AD.

(s) Contact Ian Dargin, Aerospace Engineer, Engine Certification Office, FAA, Engine and Propeller Directorate, 12 New England Executive Park, Burlington, MA 01803; telephone (781) 238–7178; fax (781) 238–7199; e-mail: *ian.dargin@faa.gov* for more information about this AD.

Material Incorporated by Reference

(t) You must use the service information specified in Table 6 to perform the actions required by this AD. The Director of the Federal Register approved the incorporation by reference of the documents listed in Table 6 of this AD in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. Contact Rolls-Royce plc, P.O. Box 31 Derby, DE248BJ, United Kingdom; telephone 011–44–1332–242424; fax 011–44–1332–249936 for a copy of this service information. You may review copies at the FAA, New England Region, Office of the Regional Counsel, 12 New England Executive Park, Burlington, MA; or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal-register/cfr/ibr-locations.html.*

TABLE 6.—INCORPORATION BY REFERENCE

Rolls-Royce plc Service Bulletin (SB)/Alert Service Bulletin (ASB) No.	Page	Revision	Date
SB No. RB.211–72–E148 Total Pages: 83	All	Original	March 13, 2003.
SB No. RB.211–72–E150 Total Pages: 72	All	1	June 4, 2003.
SB No. RB.211–72–E171 Total Pages: 71	All	1	February 8, 2005
ASB No. RB.211–72–AD428 Total Pages: 27	All	5	March 18, 2005.
Appendix 1 of ASB No. RB.211–72–AD428 Total Pages: 4	All	5	March 18, 2005.
Appendix 2 of ASB No. RB.211–72–AD428 Total Pages: 2	All	5	March 18, 2005.
Appendix 3 of ASB No. RB.211–72–AD428 Total Pages: 5	All	5	March 18, 2005.
Appendix 4 of ASB No. RB.211–72–AD428 Total Pages: 2	All	5	March 18, 2005.

Issued in Burlington, Massachusetts, on March 7, 2007.

Peter A. White,

Acting Manager, Engine and Propeller Directorate, Aircraft Certification Service.

[FR Doc. E7–4536 Filed 3–14–07; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2006–26497; Directorate Identifier 2006–CE–082–AD; Amendment 39–14989; AD 2007–06–08]

RIN 2120–AA64

Airworthiness Directives; Przedsiebiorstwo Doswiadczalno-Produkcyjne Szybownictwa ''PZL–Bielsko'' Model SZD–50–3 ''Puchacz'' Gliders

AGENCY: Federal Aviation Administration (FAA), Department of Transportation (DOT).

ACTION: Final rule.

SUMMARY: We are adopting a new airworthiness directive (AD) for the products listed above. This AD results from mandatory continuing airworthiness information (MCAI) issued by an aviation authority of another country to identify and correct an unsafe condition on an aviation product. The MCAI describes the unsafe condition as:

Some cases of turnbuckle adjusting screws fatigue failure have occurred, due to lateral load component applied by pilot's foot. Such events may lead to rudder and pedals disconnection.

We are issuing this AD to require actions to correct the unsafe condition on these products.

DATES: This AD becomes effective April 19, 2007.

The Director of the Federal Register approved the incorporation by reference of certain publications listed in this AD as of April 19, 2007.

ADDRESSES: You may examine the AD docket on the Internet at *http://dms.dot.gov* or in person at the Docket Management Facility, U.S. Department of Transportation, 400 Seventh Street, SW., Nassif Building, Room PL–401, Washington, DC.

FOR FURTHER INFORMATION CONTACT: Gregory Davison, Aerospace Engineer, FAA, Small Airplane Directorate, 901 Locust, Room 301, Kansas City, Missouri 64106; *telephone:* (816) 329–4130; *fax:* (816) 329–4090.

SUPPLEMENTARY INFORMATION:

Streamlined Issuance of AD

The FAA is implementing a new process for streamlining the issuance of ADs related to MCAI. The streamlined process will allow us to adopt MCAI safety requirements in a more efficient manner and will reduce safety risks to the public. This process continues to follow all FAA AD issuance processes to meet legal, economic, Administrative Procedure Act, and **Federal Register** requirements. We also continue to meet our technical decision-making responsibilities to identify and correct unsafe conditions on U.S.-certificated products.

This AD references the MCAI and related service information that we considered in forming the engineering basis to correct the unsafe condition. The AD contains text copied from the MCAI and for this reason might not follow our plain language principles.

Discussion

We issued a notice of proposed rulemaking (NPRM) to amend 14 CFR part 39 to include an AD that would apply to the specified products. That NPRM was published in the **Federal Register** on January 5, 2007 (72 FR 485). That NPRM proposed to correct an unsafe condition for the specified products. The MCAI states that some cases of turnbuckle adjusting screws fatigue failure have occurred, due to lateral load component applied by pilot's foot. Such events may lead to rudder and pedals disconnection.

Comments

We gave the public the opportunity to participate in developing this AD. We received no comments on the NPRM or on the determination of the cost to the public.

Conclusion

We reviewed the available data and determined that air safety and the public interest require adopting the AD as proposed.

Differences Between This AD and the MCAI or Service Information

We have reviewed the MCAI and related service information and, in general, agree with their substance. But we might have found it necessary to use different words from those in the MCAI to ensure the AD is clear for U.S. operators and is enforceable. In making these changes, we do not intend to differ substantively from the information provided in the MCAI and related service information.

We might also have required different actions in this AD from those in the MCAI in order to follow FAA policies. Any such differences are highlighted in a NOTE within the AD.

Costs of Compliance

We estimate that this AD will affect 8 products of U.S. registry. We also estimate that it will take about 2 work-hours per product to comply with basic requirements of this AD. The average labor rate is $80 per work-hour. Required parts will cost about $100 per product. Where the service information lists required parts costs that are covered under warranty, we have assumed that there will be no charge for these parts. As we do not control warranty coverage for affected parties, some parties may incur costs higher than estimated here. Based on these figures, we estimate the cost of this AD to the U.S. operators to be $2,080, or $260 per product.

Authority for This Rulemaking

Title 49 of the United States Code specifies the FAA's authority to issue rules on aviation safety. Subtitle I, section 106, describes the authority of the FAA Administrator. ''Subtitle VII: Aviation Programs,'' describes in more detail the scope of the Agency's authority.

We are issuing this rulemaking under the authority described in ''Subtitle VII, Part A, Subpart III, Section 44701: General requirements.'' Under that section, Congress charges the FAA with promoting safe flight of civil aircraft in air commerce by prescribing regulations for practices, methods, and procedures the Administrator finds necessary for safety in air commerce. This regulation is within the scope of that authority because it addresses an unsafe condition that is likely to exist or develop on products identified in this rulemaking action.

Regulatory Findings

We determined that this AD will not have federalism implications under Executive Order 13132. This AD will not have a substantial direct effect on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.

For the reasons discussed above, I certify this AD:

(1) Is not a ''significant regulatory action'' under Executive Order 12866;

(2) Is not a ''significant rule'' under DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and

(3) Will not have a significant economic impact, positive or negative, on a substantial number of small entities

under the criteria of the Regulatory Flexibility Act.

We prepared a regulatory evaluation of the estimated costs to comply with this AD and placed it in the AD Docket.

Examining the AD Docket

You may examine the AD docket on the Internet at *http://dms.dot.gov*; or in person at the Docket Management Facility between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains the NPRM, the regulatory evaluation, any comments received, and other information. The street address for the Docket Office (telephone (800) 647–5227) is in the **ADDRESSES** section. Comments will be available in the AD docket shortly after receipt.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

Adoption of the Amendment

■ Accordingly, under the authority delegated to me by the Administrator, the FAA amends 14 CFR part 39 as follows:

PART 39—AIRWORTHINESS DIRECTIVES

■ 1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

■ 2. The FAA amends § 39.13 by adding the following new AD:

2007–06–08 Przedsiebiorstwo Doswiadczalno-Produkcyjne Szybownictwa ''PZL-Bielsko'': Amendment 39–14989; Docket No. FAA–2006–26497; Directorate Identifier 2006–CE–082–AD.

Effective Date

(a) This airworthiness directive (AD) becomes effective April 19, 2007.

Affected ADs

(b) None.

Applicability

(c) This AD applies to Model SZD–50–3 ''Puchacz'' Gliders, all serial numbers, certificated in any category.

Reason

(d) The mandatory continuing airworthiness information (MCAI) states:

Some cases of turnbuckle adjusting screws fatigue failure have occurred, due to lateral load component applied by pilot's foot. Such events may lead to rudder and pedals disconnection.

Actions and Compliance

(e) Unless already done, within the next 3 calendar months after April 19, 2007 (the effective date of this AD), install the extra pull rod between the rear pedals and turnbuckle adjusting screws following Allstar PZL Glider Sp. Z o.o. Mandatory Service Bulletin No. BE–057/SZD–50–3/2006 ''PUCHACZ'', dated October 16, 2006, except as specified in paragraphs (e)(1) through (e)(4) of this AD. For owners/operators that have installed an additional short cable between the rear seat pedal and turnbuckle prior to Allstar PZL's issuance of Mandatory Service Bulletin No. BE–057/SZD–50–3/2006 ''PUCHACZ'', dated October 16, 2006, this additional short cable assembly must comply with the requirements of Allstar PZL Glider Sp. Z o.o. Mandatory Service Bulletin No. BE–057/SZD–50–3/2006 ''PUCHACZ'', dated October 16, 2006. Upon completion, a logbook entry is required.

(1) Paragraph 1 of Allstar PZL Glider Sp. Z o.o. Mandatory Service Bulletin No. BE–057/SZD–50–3/2006 ''PUCHACZ'', dated October 16, 2006, describes the dimension length of the extra segment pull rod to be 140 mm. Modify this to read: ''140 mm (5.5118 inches).''

(2) Paragraph 4 of Allstar PZL Glider Sp. Z o.o. Mandatory Service Bulletin No. BE–057/SZD–50–3/2006 ''PUCHACZ'', dated October 16, 2006, describes the dimensions of the short pull rod to be 3 mm diameter core and approximately 140 mm. Modify this to read: ''3 mm (0.1181 inch) and 140 mm (5.5118 inches).''

(3) Paragraph 4.4 of Allstar PZL Glider Sp. Z o.o. Mandatory Service Bulletin No. BE–057/SZD–50–3/2006 ''PUCHACZ'', dated October 16, 2006, describes a 1 mm diameter cotter pin. Modify this to read: ''1 mm (0.03937 inch).''

(4) Paragraph 5 of Allstar PZL Glider Sp. Z o.o. Mandatory Service Bulletin No. BE–057/SZD–50–3/2006 ''PUCHACZ'', dated October 16, 2006, reads, ''The parts necessary for modification are available at Allstar PZL Glider, or substitute aircraft parts may be used—capable to withstand a load of 6100N at minimum.'' Change this to read: ''The parts necessary for modification are available at Allstar PZL Glider, or substitute aircraft parts may be used—capable to withstand a load of 6100N (1,372 lbs) at minimum. If a substitute part is used, the hole diameter specified in Figure 1 of the service bulletin as 'Ø 6 Hg' means a 6 mm (0.2362 inch) diameter hole with a dimensional tolerance of +0.03 mm (+0.0012 inch). Contact the manufacturer for further details.''

FAA AD Differences

Note: This AD differs from the MCAI and/or service information as follows: Paragraphs (e)(1) through (e)(4) of this AD have been added to clarify certain procedures in the service bulletin.

Other FAA AD Provisions

(f) The following provisions also apply to this AD:

(1) *Alternative Methods of Compliance (AMOCs):* The Manager, Standards Staff, FAA, *ATTN:* Gregory Davison, Aerospace Engineer, FAA, Small Airplane Directorate, 901 Locust, Room 301, Kansas City, Missouri 64106; *telephone:* (816) 329–4130; *fax:* (816) 329–4090, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19. Before using any approved AMOC on any airplane to which the AMOC applies, notify your appropriate principal inspector (PI) in the FAA Flight Standards District Office (FSDO), or lacking a PI, your local FSDO.

(2) *Airworthy Product:* For any requirement in this AD to obtain corrective actions from a manufacturer or other source, use these actions if they are FAA-approved. Corrective actions are considered FAA-approved if they are approved by the State of Design Authority (or their delegated agent). You are required to assure the product is airworthy before it is returned to service.

(3) *Reporting Requirements:* For any reporting requirement in this AD, under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 et.seq.), the Office of Management and Budget (OMB) has approved the information collection requirements and has assigned OMB Control Number 2120–0056.

Material Incorporated by Reference

(g) You must use Allstar PZL Glider Sp. Z o.o. Mandatory Service Bulletin No. BE–057/SZD–50–3/2006 ''PUCHACZ'', dated October 16, 2006, to do the actions required by this AD, unless the AD specifies otherwise.

(1) The Director of the Federal Register approved the incorporation by reference of this service information under 5 U.S.C. 552(a) and 1 CFR part 51.

(2) For service information identified in this AD, contact AllStar PZL Glider Sp. zo.o., ul. Cieszyńska 325, 43 300 Bielsko-Biala; *telephone:* +48 (0)33 8125021; *fax:* +48 (0)33 8123739; *e-mail:* office@szd.com.pl.

(3) You may review copies at the FAA, Central Region, Office of the Regional Counsel, 901 Locust, Room 506, Kansas City, Missouri 64106; or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html*.

Issued in Kansas City, Missouri, on March 7, 2007.

David R. Showers,

Acting Manager, Small Airplane Directorate, Aircraft Certification Service.

[FR Doc. E7–4541 Filed 3–14–07; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2006–25739; Directorate Identifier 2006–CE–46–AD; Amendment 39–14988; AD 2007–06–07]

RIN 2120–AA64

Airworthiness Directives; Raytheon Aircraft Company Models 58 and G58 Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: The FAA adopts a new airworthiness directive (AD) for certain Raytheon Aircraft Company (RAC) Models 58 and G58 airplanes with optional propeller unfeathering accumulators installed. This AD requires you to inspect the left propeller accumulator oil tube assembly for any chafing; replace the propeller accumulator oil tube assembly if any chafing is found; and reposition and secure with clamps both the left engine manifold pressure hose and its metal identification tags to avoid contact with other tubes, hoses, electrical wires, parts, components, and structure. This AD results from several reports on the affected airplanes of chafing damage on the left propeller accumulator oil tube assembly. We are issuing this AD to detect, correct, and prevent any chafing damage of the left propeller accumulator oil tube assembly, which could result in loss of engine oil. Loss of engine oil may lead to fire or smoke in the engine compartment, inability to unfeather the propeller, engine damage, or loss of engine power.

DATES: This AD becomes effective on April 19, 2007.

The Director of the Federal Register approved the incorporation by reference of certain publications listed in this AD as of April 19, 2007.

ADDRESSES: To get the service information identified in this AD, contact Raytheon Aircraft Company, 9709 E. Central, Wichita, Kansas 67201–0085; telephone: (800) 429–5372 or (316) 676–3140.

To view the AD docket, go to the Docket Management Facility; U.S. Department of Transportation, 400 Seventh Street, SW., Nassif Building, Room PL–401, Washington, DC 20590–001 or on the Internet at *http://dms.dot.gov.* The docket number is FAA–2006–25739; Directorate Identifier 2006–CE–46–AD.

FOR FURTHER INFORMATION CONTACT: Jeff Pretz, Aerospace Engineer, Wichita Aircraft Certification Office, FAA, 1801 Airport Road, Room 100, Wichita, Kansas 67209; telephone: (316) 946–4153; fax: (316) 946–4407.

SUPPLEMENTARY INFORMATION:

Discussion

On October 10, 2006, we issued a proposal to amend part 39 of the Federal Aviation Regulations (14 CFR part 39) to include an AD that would apply to certain RAC Models 58 and G58 airplanes with optional propeller unfeathering accumulators installed. This proposal was published in the **Federal Register** as a notice of proposed rulemaking (NPRM) on October 17, 2006 (71 FR 60924). The NPRM proposed to require you to inspect the left propeller accumulator oil tube assembly for any chafing; replace the propeller accumulator oil tube assembly if any chafing is found; and reposition and secure with clamps both the left engine manifold pressure hose and its metal identification tags to avoid contact with other tubes, hoses, electrical wires, parts, components, and structure.

Comments

We provided the public the opportunity to participate in developing this AD. The following presents the comments received on the proposal and FAA's response to each comment:

Comment Issue: Service Information and Derived ADs

The Modification and Replacement of Parts Association (MARPA) states that frequently ADs are derived from service information originating with the type certificate holder or its suppliers. MARPA also states that manufacturer's service documents are privately authored instruments generally enjoying copyright protection against duplication and distribution. MARPA contends that when a service document is incorporated by reference under 5 U.S.C. 552(a) and 1 CFR part 51 into a public document such as an AD, it loses its private, protected status and becomes itself a public document. MARPA explains that if a service document is used as a mandatory element of compliance it should not simply be referenced, but should be incorporated into the regulatory document. MARPA states that public laws by definition must be public, which means they cannot rely for compliance upon private writings, especially when the writings originate in a foreign country. MARPA adds that the interpretation of a document is not a question of fact, but of law, bound by the figurative four corners of the document; therefore, unless the service document is incorporated by reference, a court of law will not consider it when interpreting the AD. MARPA is concerned that failure to incorporate-by-reference the relevant service information could result in a court decision invalidating the AD.

MARPA advises that it was informed that service documents are usually not incorporated into NPRMs, but only into final actions. MARPA notes that there is no indication in the NPRM that the FAA intends to incorporate by reference the necessary service information; in addition, there is no indication of which service documents are mandatory and which are merely sources of additional service information; therefore, the reader is unsure of the FAA's intent. MARPA asks that future proposed actions indicate the FAA intent by including the following, or a similar statement: ''We intend to incorporate by reference the following publications.''

MARPA also states that incorporation by reference service documents should be made available to the public by publication in the Docket Management System (DMS) keyed to the action that incorporates them. MARPA adds that, under the aforementioned authorities, incorporation by reference is a technique used to reduce the size of the **Federal Register** when the information is already available to the affected individuals. MARPA notes that, traditionally, ''affected individuals'' has meant aircraft owners and operators who are generally provided service information by the manufacturer. MARPA states that a new class of affected individuals has emerged since the majority of aircraft maintenance is now performed by specialty shops instead of aircraft owners and operators.

MARPA adds that this new class includes maintenance and repair organizations (MRO), component servicing and repair shops, parts purveyors and distributors and organizations manufacturing or servicing alternatively certified parts under section 21.303 (''Replacement and modification parts'') of the Federal Aviation Regulations (14 CFR 21.303). Further, MARPA notes that the concept of brevity is now nearly archaic as documents exist more frequently in electronic format than on paper. Therefore, MARPA asks that the service documents deemed essential to the accomplishment of the NPRM be incorporated by reference into the regulatory instrument, and published in DMS prior to release of the AD.

We understand MARPA's comment concerning incorporation by reference.

The Office of the Federal Register (OFR) requires that documents that are necessary to accomplish the requirements of the AD be incorporated by reference during the final rule phase of rulemaking. This final rule incorporates by reference the documents necessary for the accomplishment of the requirements mandated by this AD. Further, we point out that while documents that are incorporated by reference do become public information, they do not lose their copyright protection. For that reason, we advise the public to contact the manufacturer to obtain copies of the referenced service information.

The FAA does not concur with the commenter's request to indicate in an NPRM our intent to incorporate service information by reference. When we propose that actions be accomplished in accordance with certain service information in an NPRM, the public may assume we intend to IBR that service information, as requested by the Office of the Federal Register. Service information that is cited in the proposed AD as a source of additional information is not presented as a requirement, and the public may assume we do not intend to IBR that service information. No change to this final rule is necessary in regard to the commenter's request.

In regard to MARPA's request to post service bulletins on the Department of Transportation's DMS, we are currently in the process of reviewing issues surrounding the posting of service bulletins on the DMS as part of an AD docket. Once we have thoroughly examined all aspects of this issue and have made a final determination, we will consider whether our current practice needs to be revised. No change to the final rule is necessary in response to this comment.

Conclusion

We have carefully reviewed the available data and determined that air safety and the public interest require adopting the AD as proposed except for minor editorial corrections. We have determined that these minor corrections:

- Are consistent with the intent that was proposed in the NPRM for correcting the unsafe condition; and
- Do not add any additional burden upon the public than was already proposed in the NPRM.

Costs of Compliance

We estimate that this AD affects 49 airplanes in the U.S. registry.

We estimate the following costs to do the inspection:

Labor cost	Parts cost	Total cost per airplane	Total cost on U.S. operators
1 work-hour × $80 per hour = $80	$5	$85	$4,165

We estimate the following costs to do any necessary replacements that would be required based on the results of the inspection. We have no way of determining the number of airplanes that may need this replacement:

Labor cost	Parts cost	Total cost per airplane
1 work-hour × $80 per hour = $80	$39	$119

RAC will provide warranty credit as specified in RAC Mandatory Service Bulletin No. SB 61–3806, issued: August 2006.

Authority for This Rulemaking

Title 49 of the United States Code specifies the FAA's authority to issue rules on aviation safety. Subtitle I, Section 106 describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes in more detail the scope of the agency's authority.

We are issuing this rulemaking under the authority described in Subtitle VII, Part A, Subpart III, Section 44701, ''General requirements.'' Under that section, Congress charges the FAA with promoting safe flight of civil aircraft in air commerce by prescribing regulations for practices, methods, and procedures the Administrator finds necessary for safety in air commerce. This regulation is within the scope of that authority because it addresses an unsafe condition that is likely to exist or develop on products identified in this AD.

Regulatory Findings

We have determined that this AD will not have federalism implications under Executive Order 13132. This AD will not have a substantial direct effect on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.

For the reasons discussed above, I certify that this AD:

1. Is not a ''significant regulatory action'' under Executive Order 12866;
2. Is not a ''significant rule'' under the DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and
3. Will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

We prepared a summary of the costs to comply with this AD (and other information as included in the Regulatory Evaluation) and placed it in the AD Docket. You may get a copy of this summary by sending a request to us at the address listed under **ADDRESSES**. Include ''Docket No. FAA–2006–25739; Directorate Identifier 2006–CE–46–AD'' in your request.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

Adoption of the Amendment

■ Accordingly, under the authority delegated to me by the Administrator, the Federal Aviation Administration amends part 39 of the Federal Aviation Regulations (14 CFR part 39) as follows:

PART 39—AIRWORTHINESS DIRECTIVES

■ 1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

■ 2. FAA amends § 39.13 by adding a new AD to read as follows:

2007–06–07 Raytheon Aircraft Company: Amendment 39–14988; Docket No. FAA–2006–25739; Directorate Identifier 2006–CE–46–AD.

Effective Date

(a) This AD becomes effective on April 19, 2007.

Affected ADs

(b) None.

Applicability

(c) This AD applies to Models 58 and G58 airplanes, serial numbers TH–2097 through TH–2150, with optional propeller unfeathering accumulators installed, that are certificated in any category.

Unsafe Condition

(d) This AD results from several reports on the affected airplanes of chafing damage on the left propeller accumulator oil tube assembly. This includes an in-flight oil leak from the left engine on a Raytheon Aircraft Company Model G58 airplane. We are issuing this AD to detect, correct, and prevent any chafing damage of the left propeller accumulator oil tube assembly, which could result in loss of engine oil. Loss of engine oil may lead to fire or smoke in the engine compartment, inability to unfeather the propeller, engine damage, or loss of engine power.

Compliance

(e) To address this problem, you must do the following, unless already done:

Actions	Compliance	Procedures
(1) Inspect the left propeller accumulator oil tube assembly for chafing.	*For airplanes that have not had a 100-hour time-in-service (TIS) inspection or the inspection following Raytheon Safety Communiqué No. 271, dated May 2006:* Within the next 25 hours TIS after April 19, 2007 (the effective date of this AD). *For airplanes that have had a 100-hour TIS inspection or the inspection following Raytheon Safety Communiqué No. 271, dated May 2006:* Within the next 50 hours TIS after April 19, 2007 (the effective date of this AD).	Follow Raytheon Aircraft Company Mandatory Service Bulletin No. SB 61–3806, issued: August 2006.
(2) If any chafing is found in the inspection required by paragraph (e)(1) of this AD, replace the propeller accumulator oil tube assembly.	Before further flight after the inspection required by paragraph (e)(1) of this AD.	Follow Raytheon Aircraft Company Mandatory Service Bulletin No. SB 61–3806, issued: August 2006.
(3) Reposition and secure with clamps the left manifold pressure hose and its metal identification tags to ensure clearance between it and all tubes, hoses, electrical wires, parts, components, and structure.	Before further flight after the inspection or replacement required in paragraphs (e)(1) and (e)(2) of this AD.	Follow Raytheon Aircraft Company Mandatory Service Bulletin No. SB 61–3806, issued: August 2006.

Material Incorporated by Reference

(f) You must use Raytheon Aircraft Company Mandatory Service Bulletin No. SB 61–3806, issued: August 2006, to do the actions required by this AD, unless the AD specifies otherwise.

(1) The Director of the Federal Register approved the incorporation by reference of this service information under 5 U.S.C. 552(a) and 1 CFR part 51.

(2) For service information identified in this AD, contact Raytheon Aircraft Company, 9709 E. Central, Wichita, Kansas 67201–0085; telephone: (800) 429–5372 or (316) 676–3140.

(3) You may review copies at the FAA, Central Region, Office of the Regional Counsel, 901 Locust, Kansas City, Missouri 64106; or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

Issued in Kansas City, Missouri, on March 7, 2007.

David R. Showers,

Acting Manager, Small Airplane Directorate, Aircraft Certification Service.

[FR Doc. E7–4523 Filed 3–14–07; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2006–24369; Directorate Identifier 2006–NM–001–AD; Amendment 39–14990; AD 2007–06–09]

RIN 2120–AA64

Airworthiness Directives; Boeing Model 737–600, –700, –700C, and –800 Series Airplanes

AGENCY: Federal Aviation Administration (FAA), Department of Transportation (DOT).

ACTION: Final rule.

SUMMARY: The FAA is superseding an existing airworthiness directive (AD), which applies to certain Boeing Model 737–600, –700, –700C, and –800 series airplanes. That AD currently requires replacing the point ''D'' splice fitting between windows number 1 and 2 with a new splice fitting; performing an eddy current inspection for cracking of the holes in the structure common to the new splice fitting, including doing any related investigative actions; and performing corrective actions if necessary. This new AD adds repetitive inspections for cracking of the skin just below each splice fitting, and related corrective actions if necessary. This AD results from full-scale fuselage fatigue testing on the splice fitting that failed prior to the design objective on Boeing Model 737–800 series airplanes, and a report of a cracked splice fitting on an operational airplane. We are issuing this AD to prevent cracking of the existing fitting, which may result in cracking through the skin and consequent decompression of the flight deck.

DATES: This AD becomes effective April 19, 2007.

The incorporation by reference of Boeing Alert Service Bulletin 737–53A1222, Revision 3, dated January 3, 2007, as listed in the regulations, is approved by the Director of the Federal Register as of April 19, 2007.

On December 21, 2005 (70 FR 72595, December 6, 2005), the Director of the Federal Register approved the incorporation by reference of Boeing Alert Service Bulletin 737–53A1222, Revision 2, dated October 20, 2005.

ADDRESSES: You may examine the AD docket on the Internet at *http://dms.dot.gov* or in person at the Docket Management Facility, U.S. Department of Transportation, 400 Seventh Street, SW., Nassif Building, Room PL–401, Washington, DC.

Contact Boeing Commercial Airplanes, P.O. Box 3707, Seattle,

Washington 98124–2207, for service information identified in this AD.

FOR FURTHER INFORMATION CONTACT: Wayne Lockett, Aerospace Engineer, Airframe Branch, ANM–120S, FAA, Seattle Aircraft Certification Office, 1601 Lind Avenue, SW., Renton, Washington 98057–3356; telephone (425) 917–6447; fax (425) 917–6590.

SUPPLEMENTARY INFORMATION:

Examining the Docket

You may examine the airworthiness directive (AD) docket on the Internet at *http://dms.dot.gov* or in person at the Docket Management Facility office between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The Docket Management Facility office (telephone (800) 647–5227) is located on the plaza level of the Nassif Building at the street address stated in the **ADDRESSES** section.

Discussion

The FAA issued a notice of proposed rulemaking (NPRM) to amend 14 CFR part 39 to include an AD that supersedes AD 2005–25–03, amendment 39–14396 (70 FR 72595, December 6, 2005). The existing AD applies to certain Boeing Model 737–600, –700, –700C, and –800 series airplanes. That NPRM was published in the **Federal Register** on April 11, 2006 (71 FR 18251). That NPRM proposed to continue to require replacing the point ''D'' splice fitting between windows number 1 and 2 with a new splice fitting; performing an eddy current inspection for cracking of the holes in the structure common to the new splice fitting, including doing any related investigative actions; and performing corrective actions if necessary. That NPRM also proposed to add repetitive inspections for cracking of the skin just below each splice fitting, and related corrective actions if necessary.

Explanation of Revision Service Information

The NPRM referred to Boeing Alert Service Bulletin 737–53A1222, Revision 2, as the appropriate source of service information for the inspection of paragraph (g). Boeing has since revised the service bulletin. Revision 3, dated January 3, 2007, corrects and clarifies certain information and adds fastener options, but adds no additional work for airplanes with splice fittings replaced as specified in a previous version of the service bulletin. We have revised this final rule to refer to Revision 3 of the service bulletin for the inspection in paragraph (g), and to provide credit for work done in accordance with Revision 2.

Comments

We provided the public the opportunity to participate in the development of this AD. We have considered the comments that have been received on the NPRM.

Support for the NPRM

One commenter, Continental Airlines, agrees with the NPRM.

Request To Provide an Alternate Method of Compliance (AMOC)

KLM Engineering and Maintenance requests that the FAA review the inspection methods for the proposed one-time inspection of certain fastener locations during the point ''D'' splice fitting replacement. The commenter advises that, for certain fastener locations, an eddy current open fastener hole is impractical and may not even be possible due to structure build-up. The commenter requests that an AMOC be given specifying fluorescent penetrant inspections instead of the eddy current open fastener hole inspections. The commenter notes that use of the fluorescent penetrant inspections has been coordinated with the manufacturer.

Since we issued the NPRM, the manufacturer issued Revision 3 of Boeing Alert Service Bulletin (ASB) 737–53A1222. Revision 3, dated January 3, 2007, contains procedures for performing fluorescent penetrant inspections. This final rule incorporates the revised service bulletin; therefore, no AMOC will be necessary to do this type of inspection. We have not changed this AD regarding this issue.

Conclusion

We have carefully reviewed the available data, including the comments received, and determined that air safety and the public interest require adopting the AD with the changes described previously. We have determined that these changes will neither increase the economic burden on any operator nor increase the scope of the AD.

Costs of Compliance

There are about 563 airplanes of the affected design in the worldwide fleet. We estimate that about 243 airplanes are on the U.S. Register, and that the average labor rate is $80 per hour. The following table provides the estimated costs for U.S. operators to comply with this AD.

ESTIMATED COSTS

Action	Work hours	Parts	Cost per airplane	Fleet cost
Replacing splice fittings with new fittings (required by AD 2005–25–03)	36	$15,445	$18,325	$4,452,975
External detailed inspection (new action)	1	0	80	[1] 19,440

[1] Per inspection cycle.

Authority for This Rulemaking

Title 49 of the United States Code specifies the FAA's authority to issue rules on aviation safety. Subtitle I, Section 106, describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes in more detail the scope of the Agency's authority.

We are issuing this rulemaking under the authority described in Subtitle VII, Part A, Subpart III, Section 44701, ''General requirements.'' Under that section, Congress charges the FAA with promoting safe flight of civil aircraft in air commerce by prescribing regulations for practices, methods, and procedures the Administrator finds necessary for safety in air commerce. This regulation is within the scope of that authority because it addresses an unsafe condition that is likely to exist or develop on products identified in this rulemaking action.

Regulatory Findings

We have determined that this AD will not have federalism implications under Executive Order 13132. This AD will not have a substantial direct effect on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.

For the reasons discussed above, I certify that this AD:

(1) Is not a ''significant regulatory action'' under Executive Order 12866;

(2) Is not a ''significant rule'' under DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and

(3) Will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

We prepared a regulatory evaluation of the estimated costs to comply with this AD and placed it in the AD docket. See the **ADDRESSES** section for a location to examine the regulatory evaluation.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

Adoption of the Amendment

■ Accordingly, under the authority delegated to me by the Administrator, the FAA amends 14 CFR part 39 as follows:

PART 39—AIRWORTHINESS DIRECTIVES

■ 1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

■ 2. The Federal Aviation Administration (FAA) amends § 39.13 by removing amendment 39–14396 (70 FR 72595, December 6, 2005) and by adding the following new airworthiness directive (AD):

2007–06–09 Boeing: Amendment 39–14990. Docket No. FAA–2006–24369; Directorate Identifier 2006–NM–001–AD.

Effective Date

(a) This AD becomes effective April 19, 2007.

Affected ADs

(b) This AD supersedes AD 2005–25–03.

Applicability

(c) This AD applies to Boeing Model 737–600, –700, –700C, and –800 series airplanes, certificated in any category; as identified in Boeing Alert Service Bulletin (ASB) 737–53A1222, Revision 3, dated January 3, 2007.

Unsafe Condition

(d) This AD results from full-scale fuselage fatigue testing on a splice fitting that failed prior to the design objective on Boeing Model 737–800 series airplanes, and a report of a cracked splice fitting on an operational airplane. We are issuing this AD to prevent cracking of the existing fitting, which may result in cracking through the skin and consequent decompression of the flight deck.

Compliance

(e) You are responsible for having the actions required by this AD performed within the compliance times specified, unless the actions have already been done.

Restatement of Certain Requirements of AD 2005–25–03

Replacing the Splice Fittings

(f) Replace the splice fittings with new splice fittings in accordance with the Accomplishment Instructions of Boeing ASB 737–53A1222, Revision 2, dated October 20, 2005, or Revision 3, dated January 3, 2007, at the times specified in paragraph (f)(1) or (f)(2) of this AD, as applicable. Before further flight, do any related investigative actions by accomplishing all the applicable actions specified in the Accomplishment Instructions.

(1) For airplanes that have accumulated fewer than 13,500 total flight cycles as December 21, 2005 (the effective date of AD 2005–25–03): Replace prior to the accumulation of 13,500 total flight cycles, or within 1,000 flight cycles after December 21, 2005, whichever occurs later.

(2) For airplanes that have accumulated 13,500 or more total flight cycles as of December 21, 2005: Replace at the later of the times specified in paragraphs (f)(2)(i) and (f)(2)(ii) of this AD.

(i) Prior to the accumulation of 18,000 total flight cycles, or within 1,000 flight cycles after December 21, 2005, whichever occurs first.

(ii) Within 90 days after December 21, 2005.

New Requirements of This AD

Repetitive Inspections

(g) Within 24,000 flight cycles after accomplishing the actions specified in paragraph (f) of this AD, perform an external detailed inspection of the skin just below each splice fitting, in accordance with the Accomplishment Instructions of Boeing ASB 737–53A1222, Revision 3, dated January 3, 2007. Thereafter, repeat the external detailed inspections at intervals not to exceed 24,000 flight cycles.

Corrective Actions

(h) If any cracking is found during any inspection required by this AD, prior to further flight, repair in accordance with a method approved by the Manager, Seattle Aircraft Certification Office (ACO), FAA, or with a method approved in accordance with the procedures specified in paragraph (j) of this AD.

Acceptable Method of Compliance

(i) Replacing the splice fitting and any related investigative actions before December 21, 2005 (the effective date of AD 2005–25–03), in accordance with Boeing Service Bulletin 737–53–1222, dated June 6, 2002; or Boeing ASB 737–53A1222, Revision 1, dated January 30, 2003, is acceptable for compliance with the requirements of paragraph (f) of this AD. An inspection done before the effective date of this AD in accordance with Boeing ASB 737–53A1222, Revision 2, dated October 20, 2005, is acceptable for compliance with the requirements of paragraph (g) of this AD.

Alternative Methods of Compliance (AMOCs)

(j)(1) The Manager, Seattle ACO, FAA, has the authority to approve AMOCs for this AD, if requested in accordance with the procedures found in 14 CFR 39.19.

(2) Before using any AMOC approved in accordance with § 39.19 on any airplane to which the AMOC applies, notify the appropriate principal inspector in the FAA Flight Standards Certificate Holding District Office.

(3) An AMOC that provides an acceptable level of safety may be used for any repair required by this AD, if it is approved by an Authorized Representative for the Boeing Commercial Airplanes Delegation Option Authorization Organization who has been authorized by the Manager, Seattle ACO, to make those findings. For a repair method to be approved, the repair must meet the certification basis of the airplane, and the approval must specifically refer to this AD.

(4) AMOCs approved previously in accordance with AD 2005–25–03, amendment 39–14396, are approved as AMOCs for the corresponding provisions of paragraphs (f) and (h) of this AD.

Material Incorporated by Reference

(k) You must use Boeing Alert Service Bulletin 737–53A1222, Revision 2, dated October 20, 2005; or Boeing Alert Service Bulletin 737–53A1222, Revision 3, dated January 3, 2007; to perform the actions that are required by this AD, unless the AD specifies otherwise.

(1) The incorporation by reference of Boeing Alert Service Bulletin 737–53A1222, Revision 3, dated January 3, 2007, is approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51.

(2) On December 21, 2005 (70 FR 72595, December 6, 2005), the Director of the Federal Register approved the incorporation by reference of Boeing Alert Service Bulletin 737–53A1222, Revision 2, dated October 20, 2005.

(3) Contact Boeing Commercial Airplanes, P.O. Box 3707, Seattle, Washington 98124–2207, for a copy of this service information. You may review copies at the FAA, Transport Airplane Directorate, 1601 Lind Avenue, S.W., Renton, Washington; or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal-register/cfr/ibr-locations.html.*

Issued in Renton, Washington, on March 7, 2007.

Ali Bahrami,

Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. E7–4540 Filed 3–14–07; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2007–26834; Directorate Identifier 2006–NM–235–AD; Amendment 39–14984; AD 2007–06–03]

RIN 2120–AA64

Airworthiness Directives; Airbus Model A330 Airplanes

AGENCY: Federal Aviation Administration (FAA), Department of Transportation (DOT).

ACTION: Final rule.

SUMMARY: We are adopting a new airworthiness directive (AD) for the products listed above. This AD results from mandatory continuing airworthiness information (MCAI) issued by an airworthiness authority of another country to identify and correct an unsafe condition on an aviation product. The MCAI describes the unsafe condition as an incomplete discharge of the extinguishing agent in the fire zone, which could lead, in the worst case, in combination with an engine fire, to a temporary uncontrolled engine fire. We are issuing this AD to require actions to correct the unsafe condition on these products.

DATES: This AD becomes effective April 19, 2007.

The Director of the Federal Register approved the incorporation by reference of a certain publication listed in this AD as of April 19, 2007.

ADDRESSES: You may examine the AD docket on the Internet at *http://dms.dot.gov* or in person at the Docket Management Facility, U.S. Department of Transportation, 400 Seventh Street, SW., Nassif Building, Room PL–401, Washington, DC.

FOR FURTHER INFORMATION CONTACT: Todd Thompson, Aerospace Engineer, International Branch, ANM–116, FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington 98057–3356; telephone (425) 227–1175; fax (425) 227–1149.

SUPPLEMENTARY INFORMATION:

Discussion

The FAA is implementing a new process for streamlining the issuance of ADs related to MCAI. This streamlined process will allow us to adopt MCAI safety requirements in a more efficient manner and will reduce safety risks to the public. This process continues to allow all FAA AD issuance processes to meet legal, economic, Administrative Procedure Act, and **Federal Register** requirements. We also continue to meet our technical decision-making responsibilities to identify and correct unsafe conditions on U.S.-certificated products.

This AD references the MCAI and related service information that we considered in forming the engineering basis to correct the unsafe condition. The AD contains text copied from the MCAI and for this reason might not follow our plain language principles.

We issued a notice of proposed rulemaking (NPRM) to amend 14 CFR part 39 to include an AD that would apply to the specified products. That NPRM was published in the **Federal Register** on January 12, 2007 (72 FR 1470). That NPRM proposed to require a one-time detailed visual inspection for the presence of the retaining-ring on the discharge head assembly of the engine fire extinguishing system, and repair if necessary. The MCAI states that one Model A330 operator discovered that the line connection to the discharge head could not be properly secured during engine fire bottle replacement, due to a missing retaining-ring. Inspections revealed that all four discharge-heads line connectors, two per engine, were missing the retaining-ring. It was confirmed later that it was a quality issue.

The function of the retaining-ring is to secure a tight connection between the fire-extinguishing line and the discharge head. In absence of the retaining-ring, in case of activation of the fire extinguishing system, the pressure exerted by the agent on the pipe could compromise the tightness of the connection, leading to an incomplete discharge of the extinguishing agent in the fire zone.

This situation if not corrected could lead, in the worst case, in combination with an engine fire, to a temporary uncontrolled engine fire which constitutes an unsafe condition.

Comments

We gave the public the opportunity to participate in developing this AD. We considered the comment received. The commenter, Jonathan Frederick, supports the NPRM.

Conclusion

We reviewed the available data, including the comments received, and determined that air safety and the public interest require adopting the AD as proposed.

Differences Between This AD and the MCAI or Service Information

We have reviewed the MCAI and related service information and, in general, agree with their substance. But we might have found it necessary to use different words from those in the MCAI to ensure the AD is clear for U.S. operators and is enforceable in a U.S. court of law. In making these changes, we do not intend to differ substantively from the information provided in the MCAI and related service information.

We might also have required different actions in this AD from those in the MCAI in order to follow our FAA policies. Any such differences are described in a separate paragraph of the AD. These requirements, if any, take precedence over the actions copied from the MCAI.

Costs of Compliance

We estimate that this AD will affect 27 products of U.S. registry. We also estimate that it will take about 4 work-hours per product to comply with this AD. The average labor rate is $80 per work-hour. Required parts will cost about $0 per product. Where the service information lists required parts costs that are covered under warranty, we have assumed that there will be no charge for these parts. As we do not control warranty coverage for affected parties, some parties may incur costs higher than estimated here. Based on these figures, we estimate the cost of this AD to the U.S. operators to be $8,640, or $320 per product.

Authority for This Rulemaking

Title 49 of the United States Code specifies the FAA's authority to issue rules on aviation safety. Subtitle I, section 106, describes the authority of the FAA Administrator. ''Subtitle VII: Aviation Programs,'' describes in more detail the scope of the Agency's authority.

We are issuing this rulemaking under the authority described in ''Subtitle VII, Part A, Subpart III, Section 44701: General requirements.'' Under that section, Congress charges the FAA with promoting safe flight of civil aircraft in air commerce by prescribing regulations for practices, methods, and procedures the Administrator finds necessary for safety in air commerce. This regulation is within the scope of that authority because it addresses an unsafe condition that is likely to exist or develop on products identified in this rulemaking action.

Regulatory Findings

We determined that this AD will not have federalism implications under Executive Order 13132. This AD will not have a substantial direct effect on the States, on the relationship between the national government and the States,

or on the distribution of power and responsibilities among the various levels of government.

For the reasons discussed above, I certify that this AD:

(1) Is not a ''significant regulatory action'' under Executive Order 12866;

(2) Is not a ''significant rule'' under DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and

(3) Will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

We prepared a regulatory evaluation of the estimated costs to comply with this AD and placed it in the AD Docket.

Examining the AD Docket

You may examine the AD docket on the Internet at *http://dms.dot.gov;* or in person at the Docket Management Facility between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains the NPRM, the regulatory evaluation, any comments received, and other information. The street address for the Docket Office (telephone (800) 647–5227) is in the **ADDRESSES** section. Comments will be available in the AD docket shortly after receipt.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

Adoption of the Amendment

■ Accordingly, under the authority delegated to me by the Administrator, the FAA amends 14 CFR part 39 as follows:

PART 39—AIRWORTHINESS DIRECTIVES

■ 1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

■ 2. The FAA amends § 39.13 by adding the following new AD:

2007–06–03 Airbus: Amendment 39–14984. Docket No. FAA–2007–26834; Directorate Identifier 2006–NM–235–AD.

Effective Date

(a) This airworthiness directive (AD) becomes effective April 19, 2007.

Affected ADs

(b) None.

Applicability

(c) This AD applies to Airbus Model A330 airplanes, all certified models, certificated in any category, all serial numbers up to 755 included.

Reason

(d) The mandatory continuing airworthiness information (MCAI) states that one Model A330 operator discovered that the line connection to the discharge head could not be properly secured during engine fire bottle replacement, due to a missing retaining-ring. Inspections revealed that all four discharge-heads line connectors, two per engine, were missing the retaining-ring. It was confirmed later that it was a quality issue. The function of the retaining-ring is to secure a tight connection between the fire-extinguishing line and the discharge head. In absence of the retaining-ring, in case of activation of the fire extinguishing system, the pressure exerted by the agent on the pipe could compromise the tightness of the connection, leading to an incomplete discharge of the extinguishing agent in the fire zone. This situation if not corrected could lead, in the worst case, in combination with an engine fire, to a temporary uncontrolled engine fire which constitutes an unsafe condition. The MCAI requires a one-time detailed visual inspection for the presence of the retaining-ring on the discharge head assembly of engine fire extinguishing system, and repair if necessary.

Actions and Compliance

(e) Unless already done, do the following actions. Within 900 flight hours from the effective date of this AD: On both engine pylons (left hand and right hand), for all four engine fire extinguisher bottles, two per engine pylon, perform a one-time detailed visual inspection for the presence of the retaining ring on the discharge head of the bottles and apply all applicable corrective actions, in accordance with instructions defined in Airbus Service Bulletin A330–26A3037, dated July 26, 2006. Do all applicable corrective actions before further flight. Aircraft on which the four engine fire extinguishing bottles, 2 per engine pylon, have been removed and re-installed at the opportunity of hydrostatic test of engine fire extinguishing as per Airbus A330 Maintenance Review Board Report (MRBR) task 26.21.00/04, are not concerned by this AD.

Other FAA AD Provisions

(f) The following provisions also apply to this AD:

(1) *Alternative Methods of Compliance (AMOCs):* The Manager, International Branch, ANM–116, Transport Airplane Directorate, FAA, Attn: Todd Thompson, Aerospace Engineer, 1601 Lind Avenue, SW., Renton, Washington 98057–3356, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19. Before using any AMOC approved in accordance with § 39.19 on any airplane to which the AMOC applies, notify the appropriate principal inspector in the FAA Flight Standards Certificate Holding District Office.

(2) *Airworthy Product:* For any requirement in this AD to obtain corrective actions from a manufacturer or other source, use these actions if they are FAA-approved. Corrective actions are considered FAA-approved if they are approved by the State of Design Authority (or their delegated agent). You are required to assure the product is airworthy before it is returned to service.

(3) *Reporting Requirements:* For any reporting requirement in this AD, under the provisions of the Paperwork Reduction Act, the Office of Management and Budget (OMB) has approved the information collection requirements and has assigned OMB Control Number 2120–0056.

Material Incorporated by Reference

(g) You must use Airbus Service Bulletin A330–26A3037, excluding Appendix 01, dated July 26, 2006, to do the actions required by this AD, unless the AD specifies otherwise.

(1) The Director of the Federal Register approved the incorporation by reference of this service information under 5 U.S.C. 552(a) and 1 CFR part 51.

(2) For service information identified in this AD, contact Airbus, 1 Rond Point Maurice Bellonte, 31707 Blagnac Cedex, France.

(3) You may review copies at the FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington; or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal-register/cfr/ibr-locations.html.*

Issued in Renton, Washington, on March 5, 2007.

Ali Bahrami,

Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. E7–4380 Filed 3–14–07; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2006–26516; Directorate Identifier 2006–NM–173–AD; Amendment 39–14983; AD 2007–06–02]

RIN 2120–AA64

Airworthiness Directives; Airbus Model A318, A319, A320, and A321 Airplanes

AGENCY: Federal Aviation Administration (FAA), Department of Transportation (DOT).

ACTION: Final rule.

SUMMARY: The FAA is superseding an existing airworthiness directive (AD), which applies to all Airbus Model A318–100 and A319–100 series airplanes, Model A320–111 airplanes, and Model A320–200, A321–100, and A321–200 series airplanes. That AD currently requires repetitive inspections of the upper and lower attachments of the trimmable horizontal stabilizer actuator (THSA) to measure for proper

clearance and to detect cracks, damage, and metallic particles. The existing AD also requires corrective actions, if necessary, and reports of inspection findings. This new AD shortens the repetitive interval for inspecting the upper THSA attachment. This AD results from new test results on the secondary load path, which indicated the need to shorten the repetitive interval for inspecting the upper THSA attachment. We are issuing this AD to detect and correct failure of the THSA's primary load path, which could result in latent (undetected) loading and eventual failure of the THSA's secondary load path and consequent uncontrolled movement of the horizontal stabilizer and loss of control of the airplane.

DATES: This AD becomes effective April 19, 2007.

The Director of the Federal Register approved the incorporation by reference of Airbus Service Bulletin A320–27–1164, Revision 04, including Appendix 01, dated July 17, 2006, as of April 19, 2007.

On May 5, 2006 (71 FR 16203, March 31, 2006), the Director of the Federal Register approved the incorporation by reference of Airbus Service Bulletin A320–27–1164, Revision 03, including Appendix 01, dated August 24, 2005.

ADDRESSES: You may examine the AD docket on the Internet at *http://dms.dot.gov* or in person at the Docket Management Facility, U.S. Department of Transportation, 400 Seventh Street, SW., Nassif Building, Room PL–401, Washington, DC.

Contact Airbus, 1 Rond Point Maurice Bellonte, 31707 Blagnac Cedex, France, for service information identified in this AD.

FOR FURTHER INFORMATION CONTACT: Tim Dulin, Aerospace Engineer, International Branch, ANM–116, FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington 98057–3356; telephone (425) 227–2141; fax (425) 227–1149.

SUPPLEMENTARY INFORMATION:

Examining the Docket

You may examine the airworthiness directive (AD) docket on the Internet at *http://dms.dot.gov* or in person at the Docket Management Facility office between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The Docket Management Facility office (telephone (800) 647–5227) is located on the plaza level of the Nassif Building at the street address stated in the **ADDRESSES** section.

Discussion

The FAA issued a notice of proposed rulemaking (NPRM) to amend 14 CFR part 39 to include an AD that supersedes AD 2006–07–09, amendment 39–14536 (71 FR 16203, March 31, 2006). The existing AD applies to all Airbus Model A318–100 and A319–100 series airplanes, Model A320–111 airplanes, and Model A320–200, A321–100, and A321–200 series airplanes. That NPRM was published in the **Federal Register** on December 8, 2006 (71 FR 71103). That NPRM proposed to continue to require the existing actions (repetitive inspections of the upper and lower attachments of the trimmable horizontal stabilizer actuator (THSA) to measure for proper clearance and to detect cracks, damage, and metallic particles; corrective actions, if necessary; and reports of inspection findings). That NPRM proposed to shorten the repetitive interval for inspecting the upper THSA attachment.

Comments

We provided the public the opportunity to participate in the development of this AD. We have considered the comments that have been received on the NPRM.

Request To Extend Repetitive Interval

The NPRM proposed to reduce the existing repetitive interval for inspecting the upper attachment—from 20 months to 10 months. Agreeing with the intent of the AD, Northwest Airlines nonetheless requests that we change this inspection interval to 11 months. The commenter reports that Northwest Airlines' inspection of 139 affected airplanes during accomplishment of AD 2006–07–09 has revealed no findings. Northwest Airlines is currently working with Airbus to better understand the reasons for the reduced inspection interval for the upper attachment. Northwest Airlines' current L-check interval is 21.5 months. The commenter therefore feels that an inspection interval of 11 months for the upper attachment would allow Northwest Airlines to accomplish alternate inspections in a hangar, and yet fulfill the intent of the AD. The commenter explains that a hangar environment would allow the use of a more effective, specialized workforce, and reduce the impact of correcting any finding.

We disagree with the request to extend the compliance time. The absence of positive findings alone does not justify an extension of the compliance time in this case. The 10-month inspection interval for the upper attachment is based on the results of Airbus's tests of the endurance of the secondary load path under simulated loads. Northwest Airlines did not provide any data that would support the extension of the compliance time. We have not changed the final rule.

Conclusion

We have carefully reviewed the available data, including the comments that have been submitted, and determined that air safety and the public interest require adopting the AD as proposed.

Costs of Compliance

The following table provides the estimated costs for U.S. operators to comply with this AD, per inspection cycle.

ESTIMATED COSTS

Work hours	Average labor rate per hour	Parts	Cost per airplane	Number of U.S.-registered airplanes	Fleet cost
1	$80	None	$80	700	$56,000

Authority for This Rulemaking

Title 49 of the United States Code specifies the FAA's authority to issue rules on aviation safety. Subtitle I, Section 106, describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes in more detail the scope of the Agency's authority.

We are issuing this rulemaking under the authority described in Subtitle VII, Part A, Subpart III, Section 44701, "General requirements." Under that section, Congress charges the FAA with promoting safe flight of civil aircraft in air commerce by prescribing regulations for practices, methods, and procedures the Administrator finds necessary for safety in air commerce. This regulation is within the scope of that authority

because it addresses an unsafe condition that is likely to exist or develop on products identified in this rulemaking action.

Regulatory Findings

We have determined that this AD will not have federalism implications under Executive Order 13132. This AD will not have a substantial direct effect on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.

For the reasons discussed above, I certify that this AD:

(1) Is not a ''significant regulatory action'' under Executive Order 12866;

(2) Is not a ''significant rule'' under DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and

(3) Will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

We prepared a regulatory evaluation of the estimated costs to comply with this AD and placed it in the AD docket. See the **ADDRESSES** section for a location to examine the regulatory evaluation.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

Adoption of the Amendment

■ Accordingly, under the authority delegated to me by the Administrator, the FAA amends 14 CFR part 39 as follows:

PART 39—AIRWORTHINESS DIRECTIVES

■ 1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

■ 2. The Federal Aviation Administration (FAA) amends § 39.13 by removing amendment 39–14536 (71 FR 16203, March 31, 2006) and by adding the following new airworthiness directive (AD):

2007–06–02 Airbus: Amendment 39–14983. Docket No. FAA–2006–26516; Directorate Identifier 2006–NM–173–AD.

Effective Date

(a) This AD becomes effective April 19, 2007.

Affected ADs

(b) This AD supersedes AD 2006–07–09.

Applicability

(c) This AD applies to all Airbus Model A318, A319, A320, and A321 airplanes, certificated in any category.

Unsafe Condition

(d) This AD results from new test results on the secondary load path, which indicated the need to shorten the repetitive interval for inspecting the upper attachment of the trimmable horizontal stabilizer actuator (THSA). We are issuing this AD to detect and correct failure of the THSA's primary load path, which could result in latent (undetected) loading and eventual failure of the THSA's secondary load path and consequent uncontrolled movement of the horizontal stabilizer and loss of control of the airplane.

Compliance

(e) You are responsible for having the actions required by this AD performed within the compliance times specified, unless the actions have already been done.

Note 1: For the purposes of this AD, a detailed inspection is: ''An intensive examination of a specific item, installation, or assembly to detect damage, failure, or irregularity. Available lighting is normally supplemented with a direct source of good lighting at an intensity deemed appropriate. Inspection aids such as mirror, magnifying lenses, etc., may be necessary. Surface cleaning and elaborate procedures may be required.''

Repetitive Inspections: Lower THSA Attachment

(f) Within 20 months since first flight of the airplane, or within 600 flight hours after May 5, 2006 (the effective date of AD 2006–07–09), whichever occurs later: Do detailed inspections of the lower THSA attachments for proper clearances, and do related corrective actions as applicable, in accordance with the Accomplishment Instructions of Airbus Service Bulletin A320–27–1164, Revision 03, including Appendix 01, dated August 24, 2005; or Revision 04, including Appendix 01, dated July 17, 2006. After the effective date of this AD, only Revision 04 of the service bulletin may be used. Do corrective actions before further flight. Repeat the inspection thereafter at intervals not to exceed 20 months.

Repetitive Inspections: Upper THSA Attachment

(g) At the earlier of the times specified in paragraphs (g)(1) and (g)(2) of this AD: Do detailed inspections of the upper THSA attachment for cracks, damage, or metallic particles, and do related corrective actions as applicable, in accordance with the Accomplishment Instructions of Airbus Service Bulletin A320–27–1164, Revision 04, including Appendix 01, dated July 17, 2006, except as required by paragraph (h) of this AD. Do corrective actions before further flight. Repeat the inspections thereafter at intervals not to exceed 10 months.

(1) At the latest of the times specified in paragraphs (g)(1)(i), (g)(1)(ii), and (g)(1)(iii) of this AD.

(i) Within 10 months since the first flight of the airplane.

(ii) Within 10 months after the most recent inspection of the upper THSA attachment done in accordance with Airbus Service Bulletin A320–27–1164, Revision 02, including Appendix 01, dated March 30, 2005; Revision 03, including Appendix 01, dated August 24, 2005; or Revision 04, including Appendix 01, dated July 17, 2006.

(iii) Within 100 days after the effective date of this AD.

(2) Within 20 months after the most recent inspection of the upper THSA attachment done in accordance with Airbus Service Bulletin A320–27–1164, Revision 02, including Appendix 01, dated March 30, 2005; Revision 03, including Appendix 01, dated August 24, 2005; or Revision 04, including Appendix 01, dated July 17, 2006.

Repair Exceptions

(h) If any metallic particles are detected during any inspection required by paragraph (g) of this AD: Repair the damage before further flight in accordance with a method approved by the Manager, International Branch, ANM–116, Transport Airplane Directorate, FAA; the Direction Generale de l'Aviation Civile (DGAC) (or its delegated agent); or the European Aviation Safety Agency (EASA) (or its delegated agent).

Acceptable Prior Actions

(i) Inspections of the lower THSA attachment done before May 5, 2006, in accordance with Airbus Alert Service Bulletin A320–27A1164, dated September 10, 2004; or Airbus Service Bulletin A320–27–1164, Revision 01, including Appendix 01, dated December 17, 2004; are acceptable for compliance with the inspection requirements of paragraph (f) of this AD.

(j) Actions done before the effective date of this AD in accordance with Airbus Service Bulletin A320–27–1164, Revision 02, including Appendix 01, dated March 30, 2005; or Revision 03, including Appendix 01, dated August 24, 2005; are acceptable for compliance with the corresponding requirements of paragraphs (f) and (g) of this AD.

Inspection Reports

(k) At the applicable time specified in paragraph (k)(1) or (k)(2) of this AD, send a report of the positive findings of all inspections required by paragraphs (f) and (g) of this AD to Airbus, 1 Rond Point Maurice Bellonte, 31707 Blagnac Cedex, France. The report must include the inspection results, a description of any discrepancies found, the airplane serial number, and the number of landings and flight hours on the airplane. Using Appendix 01 of Airbus Service Bulletin A320–27–1164, Revision 02, dated March 30, 2005; Revision 03, dated August 24, 2005; or Revision 04, dated July 17, 2006; is an acceptable method to comply with this paragraph. Under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*), the Office of Management and Budget (OMB) has approved the information collection requirements contained in this AD and has assigned OMB Control Number 2120–0056.

(1) For any inspection done before the effective date of this AD: Send the report

within 30 days after the effective date of this AD.

(2) For any inspection done after the effective date of this AD: Send the report within 30 days after the inspection.

Alternative Methods of Compliance (AMOCs)

(l)(1) The Manager, International Branch, ANM–116, has the authority to approve AMOCs for this AD, if requested in accordance with the procedures found in 14 CFR 39.19.

(2) Before using any AMOC approved in accordance with § 39.19 on any airplane to which the AMOC applies, notify the appropriate principal inspector in the FAA Flight Standards Certificate Holding District Office.

Related Information

(m) EASA airworthiness directive 2006–0223, dated July 21, 2006, also addresses the subject of this AD.

Material Incorporated by Reference

(n) You must use Airbus Service Bulletin A320–27–1164, Revision 03, including Appendix 01, dated August 24, 2005; or Airbus Service Bulletin A320–27–1164, Revision 04, including Appendix 01, dated July 17, 2006; as applicable; to perform the actions that are required by this AD, unless the AD specifies otherwise.

(1) The Director of the Federal Register approved the incorporation by reference of Airbus Service Bulletin A320–27–1164, Revision 04, including Appendix 01, dated July 17, 2006, in accordance with 5 U.S.C. 552(a) and 1 CFR part 51.

(2) On May 5, 2006 (71 FR 16203, March 31, 2006), the Director of the Federal Register approved the incorporation by reference of Airbus Service Bulletin A320–27–1164, Revision 03, including Appendix 01, dated August 24, 2005.

(3) Contact Airbus, 1 Rond Point Maurice Bellonte, 31707 Blagnac Cedex, France, for a copy of this service information. You may review copies at the FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington; or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal-register/cfr/ibr-locations.html*.

Issued in Renton, Washington, on March 2, 2007.

Ali Bahrami,

Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. E7–4382 Filed 3–14–07; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2006–26231; Directorate Identifier 2006–CE–61–AD; Amendment 39–14985; AD 2007–06–04]

RIN 2120–AA64

Airworthiness Directives; EADS SOCATA Model TBM 700 Airplanes

AGENCY: Federal Aviation Administration (FAA), Department of Transportation (DOT).

ACTION: Final rule.

SUMMARY: We are adopting a new airworthiness directive (AD) for the products listed above. This AD results from mandatory continuing airworthiness information (MCAI) issued by an aviation authority of another country to identify and correct an unsafe condition on an aviation product. The MCAI describes the unsafe condition as two fatigue failures of flap carriage rollpins that occurred on in-service airplanes. We are issuing this AD to require actions to correct the unsafe condition on these products.

DATES: This AD becomes effective April 19, 2007.

The Director of the Federal Register approved the incorporation by reference of certain publications listed in this AD as of April 19, 2007.

ADDRESSES: You may examine the AD docket on the Internet at *http://dms.dot.gov* or in person at the Docket Management Facility, U.S. Department of Transportation, 400 Seventh Street, SW., Nassif Building, Room PL–401, Washington, DC.

FOR FURTHER INFORMATION CONTACT: Albert J. Mercado, Aerospace Engineer, FAA, Small Airplane Directorate, 901 Locust, Room 301, Kansas City, Missouri 64106; *telephone:* (816) 329–4119; *fax:* (816) 329–4090.

SUPPLEMENTARY INFORMATION:

Streamlined Issuance of AD

The FAA is implementing a new process for streamlining the issuance of ADs related to MCAI. The streamlined process will allow us to adopt MCAI safety requirements in a more efficient manner and will reduce safety risks to the public. This process continues to follow all FAA AD issuance processes to meet legal, economic, Administrative Procedure Act, and **Federal Register** requirements. We also continue to meet our technical decision-making responsibilities to identify and correct unsafe conditions on U.S.-certificated products.

This AD references the MCAI and related service information that we considered in forming the engineering basis to correct the unsafe condition. The AD contains text copied from the MCAI and for this reason might not follow our plain language principles.

Discussion

We issued a notice of proposed rulemaking (NPRM) to amend 14 CFR part 39 to include an AD that would apply to the specified products. That NPRM was published in the **Federal Register** on December 26, 2006 (71 FR 77310). That NPRM proposed to correct an unsafe condition for the specified products. The MCAI states reports of two fatigue failures of flap carriage rollpins that occurred on in-service airplanes. The MCAI requires inspecting and applying torque values to the rollpins nuts.

Comments

We gave the public the opportunity to participate in developing this AD. We considered the comments received.

Comment Issue No. 1: Use Consistent Language

Raymond S. Benischeck comments on this AD due to the fact there is inconsistent language regarding the identification of the part in question. The commenter states:

> In portions of the NPRM we are told to inspect for a fracture of the flap carriage ''ROLLPINS.'' Elsewhere, the correct terminology ''ROLLER PINS'' is used. The correct terminology should be used throughout the document.

The terminology used within the Discussion and Reason sections was copied directly from the associated MCAI. We are currently trying to use the language provided to us by the foreign airworthiness authority whenever possible. For consistency, we will change the phrase ''roller pin'' to ''rollpin'' in the final rule AD action to coincide with the MCAI.

We are changing the final rule AD action based on this comment.

Comment Issue No. 2: Clarify Paragraph (e)(1) of the Proposed AD

Raymond S. Benischeck comments that clarification may be necessary in paragraph (e)(1) of the proposed AD in which instructions are given to check for correct torque of the roller pin. Although applying correct torque should reveal any discrepancies in this roller pin, the actual inspection is for the purposes of detecting broken rollpins.

The instructions to do the actions stated in paragraph (e)(1) of the proposed AD are included in the referenced service bulletins. The AD mandates use of these instructions to comply with the AD.

We are not changing the final rule AD action based on this comment.

Comment Issue No. 3: Clarify Paragraph (e)(4) of the Proposed AD

Raymond S. Benischeck comments that a question arises regarding paragraph (4) of the proposed AD. Will aircraft in compliance with SB 70–138 still be required to perform the initial inspection before terminating action is considered to be in place? The statement ''no further action is required'' could be confusing since it seems to indicate at least one inspection for rollpin torque has been accomplished. If these aircraft are exempt from the inspection portion, the exception might better be noted in the serial number applicability portion in paragraph (c) of the proposed AD.

Both the MCAI and this AD state to do the action following SB70–122, which specifies in the Compliance section that those airplanes in compliance with SB 70–138 are not affected. In paragraph (e)(4) of the proposed AD, we restated this information. If we put the statement in the Applicability section, we would also have to add a statement about compliance with SB70–122 for consistency. We usually do not reference in the Applicability section that the AD exempts those airplanes that have already complied with the service bulletin we are referencing in the AD. We have determined that the phrase ''unless already done'' in the AD, as well as the statement in paragraph (e)(4) of the proposed AD, sufficiently communicates the necessary information.

We are not changing the final rule AD action based on this comment.

Comment Issue No. 4: Update Costs of Compliance

EADS Socata comments the proposed AD specifies that required parts would cost about $100. Application of SB70–122 requires 4 cotter pins. This cost is negligible.

EADS Socata also comments the proposed AD specifies that it would take about 1 work-hour per product. EADS Socata estimates that it would take 0.5 work-hour per product to inspect all flap inboard carriage rollpins.

We agree with the commenter. We will change the Costs of Compliance section to reflect the above figures, using a work-hour number of 0.5 and a cost of parts number of $5 (negligible).

We are changing the final rule AD action based on this comment.

Comment Issue No. 5: Change the Applicability Section and Incorporate Revised Service Information

EADS Socata comments the proposed AD applies to Model TBM700 airplanes, serial numbers 1 through 268, and 270 through 327. But SB70–122, Amendment 1, applies only to Model TBM700 airplanes, serial numbers 1 through 268, and 270 through 327, totaling more than 2,500 landings.

Moreover, due to a new occurrence, EADS Socata has decided to lower this threshold to 1,500 landings and issued Amendment 2 of SB70–122, which includes this new threshold.

The AD should be modified to incorporate the revised service information and change the Applicability section to read as follows: This AD applies to Model TBM700 airplanes, serial numbers 1 through 268, and 270 through 327, totaling more than 1,500 landings.

We acknowledge the above compliance time. However, we did not incorporate a threshold into the NPRM. We used the compliance time of 100 hours time-in-service for all affected airplanes based on the type of condition and the fact that the torque value of the rollpins could be incorrect regardless of the amount of hours on the airplane.

The instructions for doing the actions required by this AD are the same in Amendment 1 and Amendment 2 of SB70–122; therefore, we will incorporate by reference Amendment 2 of SB70–122 into the final rule AD action.

Conclusion

We reviewed the available data, including the comments received, and determined that air safety and the public interest require adopting the AD with the changes described previously. We determined that these changes will not increase the economic burden on any operator or increase the scope of the AD.

Differences Between This AD and the MCAI or Service Information

We have reviewed the MCAI and related service information and, in general, agree with their substance. But we might have found it necessary to use different words from those in the MCAI to ensure the AD is clear for U.S. operators and is enforceable in a U.S. court of law. In making these changes, we do not intend to differ substantively from the information provided in the MCAI and related service information.

We might also have required different actions in this AD from those in the MCAI in order to follow FAA policies. Any such differences are described in a separate paragraph of the AD. These requirements, if any, take precedence over the actions copied from the MCAI.

Costs of Compliance

We estimate that this AD will affect 221 products of U.S. registry. We also estimate that it will take about .5 work-hours per product to comply with this AD. The average labor rate is $80 per work-hour. Required parts will cost about $5 (neglible) per product. Where the service information lists required parts costs that are covered under warranty, we have assumed that there will be no charge for these parts. As we do not control warranty coverage for affected parties, some parties may incur costs higher than estimated here. Based on these figures, we estimate the cost of this AD to the U.S. operators to be $9,945 or $45 per product.

Authority for This Rulemaking

Title 49 of the United States Code specifies the FAA's authority to issue rules on aviation safety. Subtitle I, section 106, describes the authority of the FAA Administrator. ''Subtitle VII: Aviation Programs,'' describes in more detail the scope of the Agency's authority.

We are issuing this rulemaking under the authority described in ''Subtitle VII, Part A, Subpart III, Section 44701: General requirements.'' Under that section, Congress charges the FAA with promoting safe flight of civil aircraft in air commerce by prescribing regulations for practices, methods, and procedures the Administrator finds necessary for safety in air commerce. This regulation is within the scope of that authority because it addresses an unsafe condition that is likely to exist or develop on products identified in this rulemaking action.

Regulatory Findings

We determined that this AD will not have federalism implications under Executive Order 13132. This AD will not have a substantial direct effect on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.

For the reasons discussed above, I certify this AD:

(1) Is not a ''significant regulatory action'' under Executive Order 12866;

(2) Is not a ''significant rule'' under DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and

(3) Will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

We prepared a regulatory evaluation of the estimated costs to comply with this AD and placed it in the AD Docket.

Examining the AD Docket

You may examine the AD docket on the Internet at *http://dms.dot.gov;* or in person at the Docket Management Facility between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains the NPRM, the regulatory evaluation, any comments received, and other information. The street address for the Docket Office (telephone (800) 647–5227) is in the **ADDRESSES** section. Comments will be available in the AD docket shortly after receipt.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

Adoption of the Amendment

■ Accordingly, under the authority delegated to me by the Administrator, the FAA amends 14 CFR part 39 as follows:

PART 39—AIRWORTHINESS DIRECTIVES

■ 1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

■ 2. The FAA amends § 39.13 by adding the following new AD:

2007–06–04 EADS SOCATA: Amendment 39–14985; Docket No. FAA–2006–26231; Directorate Identifier 2006–CE–61–AD.

Effective Date

(a) This airworthiness directive (AD) becomes effective April 19, 2007.

Affected ADs

(b) None.

Applicability

(c) This AD applies to Model TBM 700 airplanes, serial numbers 1 through 268, and 270 through 327, certificated in any category.

Reason

(d) The mandatory continuing airworthiness information (MCAI) states reports of two fatigue failures of flap carriage rollpins that occurred on in-service airplanes.

Actions and Compliance

(e) Unless already done, do the following actions.

(1) Within the next 100 hours time-in-service (TIS) after April 19, 2007 (the effective date of this AD), inspect all flap inboard carriage rollpins for proper torque values and correct as necessary before further flight.

(2) Repeat these inspections thereafter at intervals not to exceed 100 hours TIS and correct as necessary before further flight after the inspection in which a correction is necessary.

(3) Accomplish these actions according to the instructions given in EADS SOCATA TBM Aircraft Mandatory Service Bulletin SB 70–122, Amendment 1, dated March 2006, or EADS SOCATA TBM Aircraft Mandatory Service Bulletin SB 70–122, Amendment 2, dated January 2007, and the applicable maintenance manual.

(4) If both flap inboard carriages have been replaced following EADS SOCATA TBM Aircraft Mandatory Service Bulletin SB 70–138, dated March 2006, no further action is required. Make an entry in the logbook to show compliance with this AD.

FAA AD Differences

Note: This AD differs from the MCAI and/or service information as follows: No differences.

Other FAA AD Provisions

(f) The following provisions also apply to this AD:

(1) *Alternative Methods of Compliance (AMOCs):* The Manager, Standards Staff, FAA, Small Airplane Directorate, *ATTN:* Albert J. Mercado, Aerospace Engineer, 901 Locust, Room 301, Kansas City, Missouri 64106; *telephone:* (816) 329–4119; f*ax:* (816) 329–4090, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19.

(2) *Airworthy Product:* For any requirement in this AD to obtain corrective actions from a manufacturer or other source, use these actions if they are FAA-approved. Corrective actions are considered FAA-approved if they are approved by the State of Design Authority (or their delegated agent). You are required to assure the product is airworthy before it is returned to service.

(3) *Reporting Requirements:* For any reporting requirement in this AD, under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*), the Office of Management and Budget (OMB) has approved the information collection requirements and has assigned OMB Control Number 2120–0056.

Related Information

(h) Refer to MCAI Direction générale de l'aviation civile AD No. F–2005–017, Issue date: January 19, 2005, for related information.

Material Incorporated by Reference

(i) You must use EADS SOCATA TBM Aircraft Mandatory Service Bulletin SB 70–122, Amendment 1, dated March 2006, or EADS SOCATA TBM Aircraft Mandatory Service Bulletin SB 70–122, Amendment 2, dated January 2007, to do the actions required by this AD, unless the AD specifies otherwise.

(1) The Director of the Federal Register approved the incorporation by reference of this service information under 5 U.S.C. 552(a) and 1 CFR part 51.

(2) For service information identified in this AD, contact EADS SOCATA, Direction des Services, 65921 Tarbes Cedex 9, France; *telephone:* 33 (0)5 62 41 73 00; *fax:* 33 (0)5 62 41 76 54; or SOCATA AIRCRAFT, INC., North Perry Airport, 7501 South Airport Rd., Pembroke Pines, FL 33023; *telephone:* (954) 893–1400; *fax:* (954) 964–4141.

(3) You may review copies at the FAA, Central Region, Office of the Regional Counsel, 901 Locust, Room 506, Kansas City, Missouri 64106; or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal-register/cfr/ibr-locations.html.*

Issued in Kansas City, Missouri, on March 6, 2007.

Kim Smith,

Manager, Small Airplane Directorate, Aircraft Certification Service.

[FR Doc. E7–4383 Filed 3–14–07; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2007–27360; Directorate Identifier 2007–NM–026–AD; Amendment 39–14986; AD 2007–06–05]

RIN 2120–AA64

Airworthiness Directives; Airbus Model A318, A319, A320 and A321 Airplanes

AGENCY: Federal Aviation Administration (FAA), Department of Transportation (DOT).

ACTION: Final rule; request for comments.

SUMMARY: We are adopting a new airworthiness directive (AD) for the products listed above. This AD results from mandatory continuing airworthiness information (MCAI) originated by an aviation authority of another country to identify and correct an unsafe condition on an aviation product. The MCAI describes the unsafe condition as:

* * * * *

* * * updates [to the airplane maintenance manual (AMM), engine service manual (ESM), and quick engine change kit instruction manual (QECKIM)] have inadvertently introduced torque value errors for the bolts that attach the forward engine mount to the engine. * * *

* * * * *

Application of the incorrect torque to the forward engine mount bolts during maintenance could result in failure of the forward engine mount and possible separation of the engine from the airplane and damage to the wing or loss of control of the airplane. This AD requires actions that are intended to address the unsafe condition described in the MCAI.

DATES: This AD becomes effective March 30, 2007.

The Director of the Federal Register approved the incorporation by reference of certain publications, listed in the AD, as of March 30, 2007.

We must receive comments on this AD by April 16, 2007.

ADDRESSES: You may send comments by any of the following methods:

- *DOT Docket Web Site:* Go to *http://dms.dot.gov* and follow the instructions for sending your comments electronically.
- *Fax:* (202) 493–2251.
- *Mail:* Docket Management Facility, U.S. Department of Transportation, 400 Seventh Street, SW., Nassif Building, Room PL–401, Washington, DC 20590–0001.
- *Hand Delivery:* Room PL–401 on the plaza level of the Nassif Building, 400 Seventh Street, SW., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.
- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.

Examining the AD Docket

You may examine the AD docket on the Internet at *http://dms.dot.gov;* or in person at the Docket Management Facility between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains this AD, the regulatory evaluation, any comments received, and other information. The street address for the Docket Office (telephone (800) 647–5227) is in the **ADDRESSES** section. Comments will be available in the AD docket shortly after receipt.

FOR FURTHER INFORMATION CONTACT: Tim Dulin, Aerospace Engineer, International Branch, ANM–116, FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington 98057–3356; telephone (425) 227–2141; fax (425) 227–1149.

SUPPLEMENTARY INFORMATION:

Streamlined Issuance of AD

The FAA is implementing a new process for streamlining the issuance of ADs related to MCAI. This streamlined process will allow us to adopt MCAI safety requirements in a more efficient manner and will reduce safety risks to the public. This process continues to follow all FAA AD issuance processes to meet legal, economic, Administrative Procedure Act, and **Federal Register** requirements. We also continue to meet our technical decision-making responsibilities to identify and correct unsafe conditions on U.S.-certificated products.

This AD references the MCAI and related service information that we considered in forming the engineering basis to correct the unsafe condition. The AD contains text copied from the MCAI and for this reason might not follow our plain language principles.

Discussion

The European Aviation Safety Agency (EASA), which is the Technical Agent for the Member States of the European Community, has issued EASA Airworthiness Directive 2007–0036R1, dated February 27, 2007 (referred to after this as ''the MCAI''), to correct an unsafe condition for the specified products. The MCAI states:

> From May 2006, the forward engine mount removal and installation procedures (AMM, ESM, QECKIM) have been updated to add removal and installation of the support assemblies.
>
> These updates have inadvertently introduced torque value errors for the bolts that attach the forward engine mount to the engine. This condition, if not corrected, may have the following consequences:
>
> —rupture of bolts and failure of the support assembly due to overtorqued bolts;
>
> —reduced safe life of the secondary thrust load path due to low torque on monoball housing bolts.

Application of the incorrect torque to the forward engine mount bolts during maintenance could result in failure of the forward engine mount and possible separation of the engine from the airplane and damage to the wing or loss of control of the airplane. The MCAI requires inspection, replacement, and re-torque of the affected bolts and adjustment of the torque values. You may obtain further information by examining the MCAI in the AD docket.

Relevant Service Information

Airbus has issued All Operators Telex A320–71A1042, Revision 01, dated February 12, 2007. Goodrich has issued All Operators Letter CFM56–074, Revision 1, dated February 1, 2007. The actions described in this service information are intended to correct the unsafe condition identified in the MCAI.

FAA's Determination and Requirements of This AD

This product has been approved by the aviation authority of another country, and is approved for operation in the United States. Pursuant to our bilateral agreement with the State of Design Authority, we have been notified of the unsafe condition described in the MCAI and service information referenced above. We are issuing this AD because we evaluated all pertinent information and determined the unsafe condition exists and is likely to exist or develop on other products of the same type design.

Differences Between the AD and the MCAI or Service Information

We have reviewed the MCAI and related service information and, in general, agree with their substance. But we might have found it necessary to use different words from those in the MCAI to ensure the AD is clear for U.S. operators and is enforceable. In making these changes, we do not intend to differ substantively from the information provided in the MCAI and related service information.

We might also have required different actions in this AD from those in the MCAI in order to follow FAA policies. Any such differences are highlighted in a NOTE within the AD.

FAA's Determination of the Effective Date

An unsafe condition exists that requires the immediate adoption of this AD. The FAA has found that the risk to the flying public justifies waiving notice and comment prior to adoption of this rule because application of the incorrect torque to the engine mount primary and secondary load path bolts during maintenance could result in failure of the forward engine mount and possible separation of the engine from the airplane and damage to the wing or loss of control of the airplane. Therefore, we determined that notice and opportunity for public comment before issuing this AD are impracticable and that good cause exists for making this amendment effective in fewer than 30 days.

Comments Invited

This AD is a final rule that involves requirements affecting flight safety, and we did not precede it by notice and opportunity for public comment. We invite you to send any written relevant data, views, or arguments about this AD. Send your comments to an address listed under the **ADDRESSES** section. Include ''Docket No. FAA–2007–27360; Directorate Identifier 2007–NM–026–AD'' at the beginning of your comments.

We specifically invite comments on the overall regulatory, economic, environmental, and energy aspects of this AD. We will consider all comments received by the closing date and may amend this AD because of those comments.

We will post all comments we receive, without change, to *http://dms.dot.gov,* including any personal information you provide. We will also post a report summarizing each substantive verbal contact we receive about this AD.

Authority for This Rulemaking

Title 49 of the United States Code specifies the FAA's authority to issue rules on aviation safety. Subtitle I, section 106, describes the authority of the FAA Administrator. ''*Subtitle VII:* Aviation Programs,'' describes in more detail the scope of the Agency's authority.

We are issuing this rulemaking under the authority described in ''Subtitle VII, Part A, Subpart III, Section 44701: General requirements.'' Under that section, Congress charges the FAA with promoting safe flight of civil aircraft in air commerce by prescribing regulations for practices, methods, and procedures the Administrator finds necessary for safety in air commerce. This regulation is within the scope of that authority because it addresses an unsafe condition that is likely to exist or develop on products identified in this rulemaking action.

Regulatory Findings

We determined that this AD will not have federalism implications under Executive Order 13132. This AD will not have a substantial direct effect on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.

For the reasons discussed above, I certify this AD:

1. Is not a ''significant regulatory action'' under Executive Order 12866;

2. Is not a ''significant rule'' under the DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and

3. Will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

We prepared a regulatory evaluation of the estimated costs to comply with this AD and placed it in the AD docket.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

Adoption of the Amendment

■ Accordingly, under the authority delegated to me by the Administrator, the FAA amends 14 CFR part 39 as follows:

PART 39—AIRWORTHINESS DIRECTIVES

■ 1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

■ 2. The FAA amends § 39.13 by adding the following new AD:

2007–06–05 Airbus: Amendment 39–14986. Docket No. FAA–2007–27360; Directorate Identifier 2007–NM–026–AD.

Effective Date

(a) This airworthiness directive (AD) becomes effective March 30, 2007.

Affected ADs

(b) None.

Applicability

(c) This AD applies to Airbus Model A318–111 and –112; A319–111, –112, –113, –114, and –115; A320–111, –211, –212, and –214; and A321–111, –112, –211, –212, and –213 airplanes; certificated in any category; all serial numbers, which have CFM International CFM56–5A or CFM56–5B series engines installed.

Subject

(d) Powerplant.

Reason

(e) The mandatory continued airworthiness information (MCAI) states:

From May 2006, the forward engine mount removal and installation procedures (airplane maintenance manual (AMM), engine service manual (ESM), quick engine change kit instruction manual (QECKIM)) have been updated to add removal and installation of the support assemblies.

These updates have inadvertently introduced torque value errors for the bolts that attach the forward engine mount to the engine. This condition, if not corrected, may have the following consequences:

—rupture of bolts and failure of the support assembly due to overtorqued bolts;

—reduced safe life of the secondary thrust load path due to low torque on monoball housing bolts.

Application of the incorrect torque to the forward engine mount bolts during maintenance could result in failure of the forward engine mount and possible separation of the engine from the airplane and damage to the wing or loss of control of the airplane. The MCAI requires inspection, replacement, and re-torque of the affected bolts and adjustment of the torque values.

Actions and Compliance

(f) Unless already done, do the following actions.

(1) As of the effective date of this AD:

(i) Any maintenance on the engine mounts must be performed in accordance with correct instructions as identified in the Airbus All Operators Telex (AOT) A320–71A1042, Revision 01, dated February 12, 2007; or Goodrich All Operators Letter (AOL) CFM56–074, Revision 1, dated February 1, 2007; and

(ii) Any forward engine mount support assemblies fitted on an engine which is used as replacement must be fitted in accordance with correct instructions as identified in Airbus AOT A320–71A1042, Revision 01, dated February 12, 2007; or Goodrich AOL CFM56–074, Revision 1, dated February 1, 2007.

(2) For aircraft on which any forward engine mount support assembly has been installed or maintained since May 2006 using erroneous torque values given in the maintenance data identified in paragraph 1. of the Airbus AOT A320–71A1042, Revision 01, dated February 12, 2007, or where the use of correct torque values cannot be established: Within 20 days after the effective date of this AD, accomplish the actions in paragraphs (f)(2)(i), (f)(2)(ii), (f)(2)(iii), and (f)(2)(iv) of this AD, as applicable, in accordance with the instructions of Airbus AOT A320–71A1042, Revision 01, dated February 12, 2007. Aircraft on which no engine removal has been performed since aircraft delivery are not affected by this paragraph. The alternative procedure given in paragraph 4.2.3 of the AOT is acceptable, provided that the nominal torque values specified in paragraphs 4.2.1 and 4.2.2 are restored within 120 flight cycles after accomplishing paragraph 4.2.3 of the AOT.

(i) Remove and inspect the following forward engine mount bolts: 77710–5H6 (AMM item 90) and NAS2815C15H (AMM item 85).

(ii) If any bolts, 77710–5H6 (AMM item 90), are found broken during the above inspection, before further flight, replace the affected forward engine mount support assembly (AMM item 75).

(iii) Replace bolts, 77710–5H6 (AMM item 90) and NAS2815C15H (AMM item 85), with new items and torque them to the correct value.

(iv) Re-torque 77458–7H21 bolts (AMM item 95) and NAS2816C7H (AMM item 50) to the correct value.

(3) Actions done before the effective date of this AD in accordance with Airbus AOT A320–71A1042, dated February 5, 2007, are acceptable for compliance with the corresponding provisions of paragraph (f)(2) of this AD.

(4) Within 7 days after the inspection, report all findings to Airbus Customer Services, Engineering and Technical Support, Attention: Mr. J-P Pourtau SEE11; telephone +33 (0) 5 62 11 04 48; fax +33 (0) 5 61 93 36 14.

FAA AD Differences

Note: This AD differs from the MCAI and/or service information as follows: No differences.

Other FAA AD Provisions

(g) The following provisions also apply to this AD:

(1) *Alternative Methods of Compliance (AMOCs):* The Manager, International Branch, ANM–116, FAA, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19. Send information to ATTN: Tim Dulin, Aerospace Engineer, International Branch, ANM–116, FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington 98057–3356; telephone (425) 227–2141; fax (425) 227–1149. Before using any AMOC approved in accordance with § 39.19 on any airplane to which the AMOC applies, notify the appropriate principal inspector in the FAA Flight Standards Certificate Holding District Office.

(2) *Airworthy Product:* For any requirement in this AD to obtain corrective actions from a manufacturer or other source, use these actions if they are FAA-approved. Corrective actions are considered FAA-approved if they are approved by the State of Design Authority (or their delegated agent). You are required to assure the product is airworthy before it is returned to service.

(3) *Reporting Requirements:* For any reporting requirement in this AD, under the provisions of the Paperwork Reduction Act, the Office of Management and Budget (OMB) has approved the information collection requirements and has assigned OMB Control Number 2120–0056.

Related Information

(h) Refer to MCAI European Aviation Safety Agency (EASA) Airworthiness Directive 2007–0036R1, dated February 27, 2007; Airbus All Operators Telex A320–71A1042, Revision 01, dated February 12, 2007; and Goodrich All Operators Letter CFM56–074, Revision 1, dated February 1, 2007, for related information.

Material Incorporated by Reference

(i) You must use Airbus All Operators Telex A320–71A1042, Revision 01, dated February 12, 2007; or Goodrich All Operators Letter CFM56–074, Revision 1, dated February 1, 2007; as applicable; to do the actions required by this AD, unless the AD specifies otherwise.

(1) The Director of the Federal Register approved the incorporation by reference of this service information under 5 U.S.C. 552(a) and 1 CFR part 51.

(2) For service information identified in this AD, contact Airbus, 1 Rond Point Maurice Bellonte, 31707 Blagnac Cedex, France.

(3) You may review copies at the FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington; or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call (202) 741–6030, or go to: *http://www.archives.gov/federal-register/cfr/ibr-locations.html.*

Issued in Renton, Washington, on March 7, 2007.

Ali Bahrami,

Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. E7–4535 Filed 3–14–07; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA–2006–26396; Airspace Docket No. 06–AAL–40]

Revision of Class E Airspace; Red Dog, AK

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This action revises Class E airspace at Red Dog, AK. Two new Area Navigation (RNAV) Required Navigation Performance (RNP) Special Instrument Approach Procedures (SIAPs) and an RNAV RNP Special Departure Procedure (DP) are being developed for the Red Dog Airport. This rule results in the revision of Class E airspace upward from 700 feet (ft.) and 1,200 ft. above the surface near the Red Dog Airport, Red Dog, AK.

DATES: *Effective Dates:* 0901 UTC, May 10, 2007, the Director of the **Federal Register** approves this incorporation by reference action under title 1, Code of Federal Regulations, part 51, subject to the annual revision of FAA Order 7400.9 and publication of conforming amendments.

FOR FURTHER INFORMATION CONTACT: Gary Rolf, AAL–538G, Federal Aviation Administration, 222 West 7th Avenue, Box 14, Anchorage, AK 99513–7587; telephone number (907) 271–5898; fax: (907) 271–2850; e-mail: *gary.ctr.rolf@faa.gov.* Internet address: *http://www.alaska.faa.gov/at.*

SUPPLEMENTARY INFORMATION:

History

On Monday, December 18, 2006, the FAA proposed to amend part 71 of the Federal Aviation Regulations (14 CFR part 71) to revise Class E airspace upward from 700 ft. and 1,200 ft. above the surface at Red Dog, AK (71 FR 75686). The action was proposed in order to create Class E airspace sufficient in size to contain aircraft while executing two new SIAPs, and one new DP for the Red Dog Airport. The new Special approaches are (1) The RNAV RNP Runway (RWY) 05, and (2) the RNAV RNP RWY 20. The Special DP is the IHOPO ONE RNAV RNP Departure. Class E controlled airspace extending upward from 700 ft. and 1,200 ft. above the surface in the Red Dog Airport area is revised by this action.

Interested parties were invited to participate in this proposed rulemaking by submitting written comments on the proposal to the FAA. No comments have been received, thus the rule is adopted as proposed.

The area will be depicted on aeronautical charts for pilot reference. The coordinates for this airspace docket are based on North American Datum 83. The Class E airspace areas designated as 700/1,200 ft. transition areas are published in paragraph 6005 of FAA Order 7400.9P, *Airspace Designations and Reporting Points,* dated September 1, 2006, and effective September 15, 2006, which is incorporated by reference in 14 CFR 71.1. The Class E airspace designation listed in this document will be published subsequently in the Order.

The Rule

This amendment to 14 CFR part 71 revises Class E airspace at the Red Dog Airport, Alaska. This Class E airspace is revised to accommodate aircraft executing two new Special SIAPs, and one new Special DP, and will be depicted on aeronautical charts for pilot reference. The intended effect of this rule is to provide adequate controlled airspace for Instrument Flight Rule (IFR) operations at the Red Dog airport, Red Dog, Alaska.

The FAA has determined that this regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current. It, therefore—(1) Is not a ''significant regulatory action'' under Executive Order 12866; (2) is not a ''significant rule'' under DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a regulatory evaluation as the anticipated impact is so minimal. Since this a routine matter that will only affect air traffic procedures and air navigation, it is certified that this rule will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

The FAA's authority to issue rules regarding aviation safety is found in Title 49 of the United States Code. Subtitle 1, Section 106 describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs,

describes in more detail the scope of the agency's authority.

This rulemaking is promulgated under the authority described in Subtitle VII, Part A, Subpart 1, Section 40103, Sovereignty and use of airspace. Under that section, the FAA is charged with prescribing regulations to ensure the safe and efficient use of the navigable airspace. This regulation is within the scope of that authority because it creates Class E airspace sufficient in size to contain aircraft executing instrument procedures for the Red Dog Airport and represents the FAA's continuing effort to safely and efficiently use the navigable airspace.

List of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (air).

Adoption of the Amendment

■ In consideration of the foregoing, the Federal Aviation Administration amends 14 CFR part 71 as follows:

PART 71—DESIGNATION OF CLASS A, CLASS B, CLASS C, CLASS D, AND CLASS E AIRSPACE AREAS; AIRWAYS; ROUTES; AND REPORTING POINTS

■ 1. The authority citation for 14 CFR part 71 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40103, 40113, 40120; E.O. 10854, 24 FR 9565, 3 CFR, 1959–1963 Comp., p. 389.

§ 71.1 [Amemded]

■ 2. The incorporation by reference in 14 CFR 71.1 of Federal Aviation Administration Order 7400.9P, *Airspace Designations and Reporting Points,* dated September 1, 2006, and effective September 15, 2006, is amended as follows:

* * * * *

Paragraph 6005 Class E airspace extending upward from 700 feet or more above the surface of the Earth.

* * * * *

AAL AK E5 Red Dog, AK [Revised]

Red Dog, AK
(Lat. 68°01′56″ N., long. 162°53′67″ W.)
Noatak NDB/DME, AK
(Lat. 67°34′19″ N., long. 162°58′26″ W.)
Selawik, VOR/DME, AK
(Lat. 66°35′58″ N., long. 159°59′27″ W.)

* * * * *

That airspace extending upward from 700 feet above the surface within a 6.3-mile radius of the Red Dog Airport, AK; and that airspace extending upward from 1,200 ft. above the surface within a 14-mile radius of the Red Dog Airport, AK, and within 5 miles either side of a line from the Selawik VOR/DME, AK, to lat. 67°38′06″ N., long. 162°21′42″ W., to lat. 67°54′30″ N., long. 163°00′00″ W., and within 5 miles either side of a line from the Noatak NDB/DME, AK, to lat. 67°50′20″ N., long. 163°19′16″ W., and within a 5-mile radius of lat. 67°50′20″ N., long. 163°19′16″ W.

Issued in Anchorage, AK, on March 6, 2007.

Michael A. Tarr,

Acting Manager, Alaska Flight Services Information Area Group.

[FR Doc. 07–1215 Filed 3–14–07; 8:45am]

BILLING CODE 4910–13–M

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 73

[Docket No. FAA–2007–27294; Airspace Docket No. 06–ASO–17

RIN 2120–AA66

Change of Controlling Agency for Restricted Area R–6601; Fort A.P. Hill, VA

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This action updates the name of the controlling agency for Restricted Area R–6601, Fort A.P. Hill, VA. The FAA is taking this action to reflect the correct facility name. This is an administrative change that does not alter the boundaries, designated altitudes, time of designation, or activities conducted within R–6601.

DATES: *Effective Dates:* 0901 UTC, May 10, 2007.

FOR FURTHER INFORMATION CONTACT: Paul Gallant, Airspace and Rules, Office of System Operations Airspace and AIM, Federal Aviation Administration, 800 Independence Avenue, SW., Washington, DC 20591; telephone: (202) 267–8783.

SUPPLEMENTARY INFORMATION:

The Rule

This action amends Title 14 Code of Federal Regulations (14 CFR) part 73 by changing the name of the controlling agency for Restricted Area R–6601, Fort A.P. Hill, VA, from ''FAA, Potomac Approach,'' to ''FAA, Potomac TRACON.'' This change is administrative only and does not affect the boundaries, designated altitudes, or activities conducted within the restricted areas. Therefore, notice and public procedure under 5 U.S.C. 553(b) is unnecessary.

Section 73.66 of Title 14 CFR part 73 was republished in FAA Order 7400.8N, dated February 16, 2007.

The FAA has determined that this regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current. Therefore, this regulation: (1) Is not a ''significant regulatory action'' under Executive Order 12866; (2) is not a ''significant rule'' under Department of Transportation Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a regulatory evaluation as the anticipated impact is so minimal. Since this is a routine matter that will only affect air traffic procedures and air navigation, it is certified that this rule, when promulgated, will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

Environmental Review

The FAA has determined that this action qualifies for categorical exclusion under the National Environmental Policy Act in accordance with 311d., FAA Order 1050.1E, ''Environmental Impacts: Policies and Procedures.'' This airspace action is not expected to cause any potentially significant environmental impacts, and no extraordinary circumstances exist that warrant preparation of an environmental assessment.

List of Subjects in 14 CFR Part 73

Airspace, Prohibited Areas, Restricted Areas.

Adoption of the Amendment

■ In consideration of the foregoing, the Federal Aviation Administration amends 14 CFR part 73 as follows:

PART 73—SPECIAL USE AIRSPACE

■ 1. The authority citation for part 73 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40103, 40113, 40120; E.O. 10854, 24 FR 9565, 3 CFR, 1959–1963 Comp., p. 389.

§ 73.66 [Amended]

■ 2. § 73.66 is amended as follows:

* * * * *

R–6601 Fort A.P. Hill, VA [Amended]

■ Under controlling agency, by removing the words ''FAA, Potomac Approach,'' and inserting the words ''FAA, Potomac TRACON.''

* * * * *

Issued in Washington, DC, on March 8, 2007.

Ellen Crum,

Acting Manager, Airspace and Rules.

[FR Doc. E7–4683 Filed 3–14–07; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 121

[Docket No. FAA–1998–4521; Amendment No. 121–332]

RIN 2120–AF07

Drug and Alcohol Testing Requirements

AGENCY: Federal Aviation Administration, DOT.

ACTION: Final rule; technical amendment.

SUMMARY: The Federal Aviation Administration (FAA) is making minor technical changes to update references to various types of commercial operators within the drug and alcohol testing regulations. In the final rule, ''National Air Tour Safety Standards'' (Air Tours) published on February 13, 2007, we changed the regulatory sections that referred to sightseeing operators that did not hold a certificate but that continued to be subject to drug and alcohol testing requirements. In addition, this technical amendment updates other references in the drug and alcohol testing regulations including addresses. The intent of this amendment is to avoid confusion created by inconsistent terms and references within the FAA's regulations.

DATES: *Effective Dates:* Effective on March 15, 2007.

FOR FURTHER INFORMATION CONTACT: Patrice M. Kelly, Deputy Division Manager, Drug Abatement Division, Office of Aerospace Medicine, 800 Independence Ave. SW., Washington, DC, 20591. (202) 267–3123; *patrice.kelly@faa.gov.*

SUPPLEMENTARY INFORMATION:

Technical Amendment

This technical amendment will update several references in the FAA's drug and alcohol testing regulations in Title 14 of the Code of Federal Regulations (14 CFR), part 121, appendices I and J. In addition, this amendment will change the location where registrations will be sent, so that the appropriate offices will receive the drug and alcohol testing registration information.

Since the inception of the drug testing rules in 1988, and the alcohol testing regulations in 1994, the FAA has included any sightseeing operator defined in 14 CFR 135.1(c) as an ''employer'' that was required to meet the drug and alcohol testing requirements set forth in 14 CFR part 121, appendices I and J. Under the Air Tours final rule, the FAA has moved the former § 135.1(c) operators to the newly created § 91.147 of 14 CFR. In this amendment, we are changing all references to the term ''Operator'' as defined in § 135.1(c) to reference the new definition of ''Operator'' in § 91.147.

The ''National Air Tour Safety Standards'' final rule requires that a § 91.147 operator register its drug and alcohol testing program with the Flight Standards District Office nearest its principal place of business. The technical amendment reflects that change to several sections in appendices I and J of part 121. If this change is not made, these small operators would be required to file the same company contact information with multiple FAA offices. The amendment also updates the addresses where a repair station can file its program with the FAA, if the repair station opts to have its own testing program.

We are updating references to ''a part 121 certificate holder'' and ''a part 135 certificate holder.'' The drug and alcohol testing regulations will now refer to ''part 119 certificate holders with authority to operate under parts 121 and/or 135,'' which is a technically more accurate description.

In both appendix I, section IX, and appendix J, section VII, we eliminated paragraph ''C.2'' to incorporate it in the caption within the chart. The chart that appeared in paragraph ''C.2'' now appears in the newly redesignated paragraph ''C.'' We made this change to avoid confusion and redundancy. We also removed an ''e.g.'' provision in the C.2 chart found in both appendix I, section IX, and appendix J, section VII. The ''e.g.'' in paragraph ''C.2'' was not used elsewhere in the charts, and was not a substantive provision.

Justification for Immediate Adoption

On the basis of the above, the FAA does not find that this amendment is a substantial action that requires 30 days after publication before it becomes effective, and that notice and public comment under 5 U.S.C. 533(b) are unnecessary and contrary to the public interest. Further, I find that good cause exists under 5 U.S.C. 533(d) for making this rule effective on the same day that the National Air Tour Safety Standards final rule becomes effective (March 15, 2007), so that references to sections amended in the final rule are up to date.

List of Subjects in 14 CFR Part 121

Aircraft, Airmen, Aviation Safety, Reporting and recordkeeping requirements.

■ Accordingly, Title 14 of the Code of Federal Regulations (CFR) part 121 is amended as follows:

PART 121—OPERATING REQUIREMENTS: DOMESTIC, FLAG, AND SUPPLEMENTAL OPERATIONS

■ 1. The authority citation for part 121 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 40119, 41706, 44101, 44701–44702, 44705, 44709–44711, 44713, 44716–44717, 44722, 44901, 44903–44904, 44912, 45101–45105, 46105.

■ 2. Amend appendix I to part 121 as follows:

■ A. Amend section II, to revise the definition of ''Employer''; and

■ B. Amend section IX by revising paragraphs A, B, C, D.1.e., E.1.f., and E.2.

The revisions read as follows:

Appendix I to Part 121—Drug Testing Program

* * * * *

II. *Definitions.* * * *

* * * * *

Employer is a part 119 certificate holder with authority to operate under parts 121 and/or 135, an operator as defined in § 91.147 of this chapter, or an air traffic control facility not operated by the FAA or by or under contract to the U.S. Military. An employer may use a contract employee who is not included under that employer's FAA-mandated antidrug program to perform a safety-sensitive function only if that contract employee is included under the contractor's FAA-mandated antidrug program and is performing a safety-sensitive function on behalf of that contractor (i.e., within the scope of employment with the contractor.)

* * * * *

IX. *Implementing an Antidrug Program.*

A. Each company must meet the requirements of this appendix. Use the following chart to determine whether your company must obtain an Antidrug and Alcohol Misuse Prevention Program Operations Specification or whether you must register with the FAA:

If you are . . .	You must . . .
1. A part 119 certificate holder with authority to operate under parts 121 and/or 135.	Obtain an Antidrug and Alcohol Misuse Prevention Program Operations Specification by contacting your FAA Principal Operations Inspector.
2. An operator as defined in § 91.147 of this chapter.	Register with the FAA by contacting the Flight Standards District Office nearest to your principal place of business.
3. An air traffic control facility not operated by the FAA or by or under contract to the U.S. Military.	Register with the FAA, Office of Aerospace Medicine, Drug Abatement Division (AAM–800), 800 Independence Avenue, SW., Washington, DC 20591.
4. A part 145 certificate holder who has your own antidrug program.	Obtain an Antidrug and Alcohol Misuse Prevention Program Operations Specification by contacting your Principal Maintenance Inspector or register with the FAA, Office of Aerospace Medicine, Drug Abatement Division (AAM–800), 800 Independence Avenue, SW., Washington, DC 20591, if you opt to conduct your own antidrug program.
5. A contractor who has your own antidrug program.	Register with the FAA, Office of Aerospace Medicine, Drug Abatement Division (AAM–800), 800 Independence Avenue, SW., Washington, DC 20591, if you opt to conduct your own antidrug program.

B. Use the following chart for implementing an antidrug program if you are applying for a part 119 certificate with authority to operate under parts 121 or 135, if you intend to begin operations as defined in § 91.147 of this chapter, or if you intend to begin air traffic control operations (not operated by the FAA or by or under contract to the U.S. Military). Use it to determine whether you need to have an Antidrug and Alcohol Misuse Prevention Program Operations Specification, or whether you need to register with the FAA. Your employees who perform safety-sensitive duties must be tested in accordance with this appendix. The chart follows:

If you . . .	You must . . .
1. Apply for a part 119 certificate with authority to operate under parts 121 or 135.	a. Have an Antidrug and Alcohol Misuse Prevention Program Operations Specification, b. Implement an FAA antidrug program no later than the date you start operations, and c. Meet the requirements of this appendix.
2. Intend to begin operations as defined in § 91.147 of this chapter.	a. Register with the FAA by contacting the Flight Standards District Office nearest to your principal place of business prior to starting operations, b. Implement an FAA antidrug program no later than the date you start operations, and c. Meet the requirements of this appendix.
3. Intend to begin air traffic control operations (at an air traffic control facility not operated by the FAA or by or under contract to the U.S. Military).	a. Register with the FAA, Office of Aerospace Medicine, Drug Abatement Division (AAM–800), 800 Independence Avenue, SW., Washington, DC 20591, b. Implement an FAA antidrug program no later than the date you start operations, and c. Meet the requirements of this appendix.

C. If you are an individual or company that intends to provide safety-sensitive services by contract to a part 119 certificate holder with authority to operate under parts 121 and/or 135, an operation as defined in § 91.147 of this chapter, or an air traffic control facility not operated by the FAA or by or under contract to the U.S. Military, use the chart below to determine what you must do if you opt to have your own antidrug program:

If you . . .	And you opt to conduct your own antidrug program, you must . . .
a. Are a part 145 certificate holder.	i. Have an Antidrug and Alcohol Misuse Prevention Program Operations Specification or register with the FAA, Office of Aerospace Medicine, Drug Abatement Division (AAM–800), 800 Independence Avenue, SW., Washington, DC 20591, ii. Implement an FAA Antidrug Program no later than the date you start performing safety-sensitive functions for a part 119 certificate holder with authority to operate under parts 121 or 135, or operator as defined in § 91.147 of this chapter, and iii. Meet the requirements of this appendix as if you were an employer.
b. Are a contractor.	i. Register with the FAA, Office of Aerospace Medicine, Drug Abatement Division (AAM–800), 800 Independence Avenue, SW., Washington, DC 20591, ii. Implement an FAA Antidrug Program no later than the date you start performing safety-sensitive functions for a part 119 certificate holder with authority to operate under parts 121 or 135, an operator as defined in § 91.147 of this chapter, or an air traffic control facility not operated by the FAA or by or under contract to the U.S. Military, and iii. Meet the requirements of this appendix as if you were an employer.

D. 1. * * *

e. Whether you have 50 or more safety-sensitive employees, or 49 or fewer safety-sensitive employees. (Part 119 certificate holders with authority to operate only under part 121 are not required to provide this information.)

* * * * *

E. 1. * * *

f. A signed statement indicating that: Your company will comply with this appendix, appendix J of this part, and 49 CFR part 40; and, if you are a contractor, you intend to provide safety-sensitive functions by contract to a part 119 certificate holder with authority to operate under part 121 and/or part 135, an operator as defined in § 91.147 of this chapter, or an air traffic control facility not operated by the FAA or by or under contract to the U.S. Military.

2. Send this information in the form and manner prescribed by the Administrator, in duplicate to the appropriate address below:

a. For § 91.147 operators: the Flight Standards District Office nearest to your principal place of business.

b. For all others: The Federal Aviation Administration, Office of Aerospace Medicine, Drug Abatement Division (AAM–800), 800 Independence Avenue, SW., Washington, DC 20591.

* * * * *

■ 3. Amend appendix J to part 121 as follows:

■ A. In section I., amend paragraph D. to revise the definition of ''Employer'';

■ B. Amend section VII by revising paragraphs A, B, C, D.1.e., E.1.f., E.2., and E.3.

The revisions read as follows:

Appendix J to Part 121—Alcohol Misuse Prevention Program

* * * * *

I. GENERAL

* * * * *

D. *Definitions.*

* * * * *

Employer means a part 119 certificate holder with authority to operate under parts 121 and/or 135; an operator as defined in § 91.147 of this chapter; or an air traffic control facility not operated by the FAA or by or under contract to the U.S. Military.

* * * * *

VII. HOW TO IMPLEMENT AN ALCOHOL MISUSE PREVENTION PROGRAM

A. Each company must meet the requirements of this appendix. Use the following chart to determine whether your company must obtain an Antidrug and Alcohol Misuse Prevention Program Operations Specification or whether you must register with the FAA:

If you are . . .	You must . . .
1. A part 119 certificate holder with authority to operate under parts 121 and/or 135.	Obtain an Antidrug and Alcohol Misuse Prevention Program Operations Specification by contacting your FAA Principal Operations Inspector.
2. An operator as defined in § 91.147	Register with the FAA by contacting the Flight Standards District Office nearest to your principal place of business.
3. An air traffic control facility not operated by the FAA or by or under contract to the U.S. Military.	Register with the FAA, Office of Aerospace Medicine, Drug Abatement Division (AAM–800), 800 Independence Avenue, SW., Washington, DC 20591.
4. A part 145 certificate holder who has your own alcohol misuse prevention program.	Obtain an Antidrug and Alcohol Misuse Prevention Program Operations Specification by contacting your FAA Principal Maintenance Inspector or register with the FAA, Office of Aerospace Medicine, Drug Abatement Division (AAM–800), 800 Independence Avenue, SW., Washington, DC 20591, if you opt to conduct your own Alcohol Misuse Prevention Program.
5. A contractor who has your own alcohol misuse prevention program.	Register with the FAA, Office of Aerospace Medicine, Drug Abatement Division (AAM–800), 800 Independence Avenue, SW., Washington, DC 20591 if you opt to conduct your own Alcohol Misuse Prevention Program.

B. Use the following chart for implementing an Alcohol Misuse Prevention Program if you are applying for a part 119 certificate with authority to operate under parts 121 and/or 135, if you intend to begin operations as defined in § 91.147 of this chapter, or if you intend to begin air traffic control operations (not operated by the FAA or by or under contract to the U.S. Military). Use it to determine whether you need to have an Antidrug and Alcohol Misuse Prevention Program Operations Specification, or whether you need to register with the FAA. Your employees who perform safety-sensitive duties must be tested in accordance with this appendix. The chart follows:

If you . . .	You must . . .
1. Apply for a part 119 certificate with authority to operate under parts 121 and/or 135.	a. Have an Antidrug and Alcohol Misuse Prevention Program Operations Specification, b. Implement an FAA Alcohol Misuse Prevention Program no later than the date you start operations, and c. Meet the requirements of this appendix.
2. Intend to begin operations as defined in § 91.147 of this chapter.	a. Register with the FAA by contacting the Flight Standards District Office nearest to your principal place of business prior to starting operations, b. Implement an FAA Alcohol Misuse Prevention Program no later than the date you start operations, and c. Meet the requirements of this appendix.
3. Intend to begin air traffic control operations (at an air traffic control facility not operated by the FAA or by or under contract to the U.S. Military).	a. Register with the FAA, Office of Aerospace Medicine, Drug Abatement Division (AAM–800), 800 Independence Avenue, SW., Washington, DC 20591, b. Implement an FAA antidrug program no later than the date you start operations, and c. Meet the requirements of this appendix.

C. If you are an individual or a company that intends to provide safety-sensitive services by contract to a part 119 certificate holder with authority to operate under parts 121 and/or 135 or an operator as defined in § 91.147 of this chapter, use the chart below to determine what you must do if you opt to have your own Alcohol Misuse Prevention Program:

If you . . .	And you opt to conduct your own Alcohol Misuse Prevention Program, you must . . .
a. Are a part 145 certificate holder	i. Have an Antidrug and Alcohol Misuse Prevention Program Operations Specification or register with the FAA, Office of Aerospace Medicine, Drug Abatement Division (AAM–800), 800 Independence Avenue, SW., Washington, DC 20591, ii. Implement an FAA Alcohol Misuse Prevention Program no later than the date you start performing safety-sensitive functions for a part 119 certificate holder with authority to operate under parts 121 and/or 135, or operator as defined in § 91.147 of this chapter, and iii. Meet the requirements of this appendix as if you were an employer.

If you . . .	And you opt to conduct your own Alcohol Misuse Prevention Program, you must . . .
b. Are a contractor	i. Register with the FAA, Office of Aerospace Medicine, Drug Abatement Division (AAM–800), 800 Independence Avenue, SW., Washington, DC 20591, ii. Implement an FAA Alcohol Misuse Prevention Program no later than the date you start performing safety-sensitive functions for a part 119 certificate holder with authority to operate under parts 121 and/or 135, or operator as defined in § 91.147 of this chapter, and iii. Meet the requirements of this appendix as if you were an employer.

D. 1. * * *

e. Whether you have 50 or more covered employees, or 49 or fewer covered employees. (Part 119 certificate holders with authority to operate only under part 121 are not required to provide this information.)

* * * * *

E. 1. * * *

f. A signed statement indicating that: Your company will comply with this appendix, appendix I of this part, and 49 CFR part 40; and, if you are a contractor, you intend to provide safety-sensitive functions by contract to a part 119 certificate holder with authority to operate under part 121 and/or 135, an operator as defined by § 91.147 of this chapter, or an air traffic control facility not operated by the FAA or by or under contract to the U.S. Military.

2. Send this information in the form and manner prescribed by the Administrator, in duplicate to the appropriate address below:

a. For § 91.147 operators: The Flight Standards District Office nearest to your principal place of business.

b. For all others: The Federal Aviation Administration, Office of Aerospace Medicine, Drug Abatement Division (AAM–800), 800 Independence Avenue, SW., Washington, DC 20591.

3. Update the registration information as changes occur. Send the updates in duplicate to the address specified in paragraph 2.

* * * * *

Issued in Washington, DC, on March 7, 2007.

Rebecca B. MacPherson,

Assistant Chief Counsel for Regulations.

[FR Doc. E7–4583 Filed 3–14–07; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF JUSTICE

Bureau of Prisons

28 CFR Part 552

[BOP–1107–F]

RIN 1120–AB06

Suicide Prevention Program

AGENCY: Bureau of Prisons, Justice.

ACTION: Final rule.

SUMMARY: In this document, the Bureau of Prisons (Bureau) revises its regulations on the suicide prevention program for clarity and to remove agency management procedures which do not need to be stated in regulations. We intend the revised regulations to provide for the health and safety of inmates.

DATES: March 15, 2007.

ADDRESSES: Rules Unit, Office of General Counsel, Bureau of Prisons, HOLC Room 977, 320 First Street, NW., Washington, DC 20534.

FOR FURTHER INFORMATION CONTACT: Sarah Qureshi, Office of General Counsel, Bureau of Prisons, phone (202) 207–2105.

SUPPLEMENTARY INFORMATION: The Bureau is revising its regulations on the suicide prevention program (28 CFR part 552, subpart E). We published a proposed rule on November 13, 2000 (65 FR 67670). We received one comment.

What change is the Bureau making?

We are revising the regulations generally for clarity and to remove procedures relating to agency management. The revised regulations more clearly describe for the inmate how we identify and protect inmates at risk for suicide.

Procedures relating to agency management are exempt from the rulemaking provisions of the Administrative Procedure Act (5 U.S.C. 553). Removing these procedures from the regulations allows us to speak more directly to inmates.

Revised § 552.40 more precisely states the purpose of our suicide prevention program and summarizes how we place inmates in and remove them from the program. Former §§ 552.41 through 552.43 are combined in a new § 552.41 which details the specific procedures we use to identify, refer, assess, and treat potentially suicidal inmates.

We combined provisions for the conditions of a suicide watch in former §§ 552.44, 552.46, and 552.48 in the new § 552.42. The revised regulations are more objective based. For example, the revised regulations require that rooms designated for housing an inmate on suicide watch must allow staff to maintain adequate control of the inmate without compromising the ability to observe and protect the inmate.

Previously, the regulations relied upon a more prescriptive approach of describing the location of the room (''* * * a non-administrative detention/segregation cell ordinarily in the health services area''). This prescriptive approach does not take into account recent developments in correctional facility design and construction, and has become unnecessarily restrictive.

Former §§ 552.45 and 552.49 addressed agency management procedures, and former § 552.47 affirms that a previously imposed sanction remains in effect for an inmate when that inmate is removed from a suicide watch. Because our regulations on inmate discipline sufficiently support that statement, we removed these three sections.

Response to Comment

We received one comment on our proposed rulemaking. The commenter had three main areas of concern, which we address below:

Section 552.40: The commenter stated that ''there should be a brief explanation of what a suicide watch is'' in the rules.

We present just such a brief explanation of ''suicide watch'' in § 552.42. In this section, we explain in detail the housing arrangements and conditions under which the suicidal inmate is constantly observed. Therefore, it is not necessary to define the term suicide watch in § 552.40.

Section 552.41: The commenter recommended the use of a ''buddy system'' to prevent suicide, suggesting that highly-regarded inmates might be chosen to ''look after'' or ''befriend'' the suicidal inmate. The commenter also suggested that we have a ''small team working together'' so that the suicidal inmate would ''get to know and associate and even depend on that team.''

Each new inmate who enters a Bureau facility receives written material and an orientation that explains what to expect and how to get help from staff. Additionally, all new inmates receive a confidential medical and mental health screening by a medical professional to identify those who need assistance or have the potential for becoming suicidal. These inmates are immediately referred to a mental health professional for individual assessment and appropriate treatment. Therefore, an

inmate ''Buddy System'' is not necessary.

Section 552.42: Finally, the commenter stated that the ''Warden should not have so much power.'' Particularly, the commenter referred to § 552.42(b)(2), which states that ''[o]nly the Warden may authorize the use of inmate observers.'' The commenter suggests that inmates instead go through training to become suicide watch observers.

In fact, the commenter's suggestion is our current practice. The Suicide Prevention Program Coordinator selects, trains, and evaluates inmate observers. A great responsibility rests with those assigned to observe the inmate and immediately report any attempt to do self-harm.

For that reason, the decision to use Bureau staff or inmates is a critical decision which the Warden must make after input from the Suicide Prevention Program Coordinator. Elevating this decision to the Warden level ensures that all staff understand the importance of properly observing the inmate and providing appropriate care.

For the reasons stated above, we do not change the final rule in light of the comment we received.

Executive Order 12866

This regulation has been drafted and reviewed in accordance with Executive Order 12866, ''Regulatory Planning and Review'', section 1(b), Principles of Regulation. The Director, Bureau of Prisons has determined that this rule is not a ''significant regulatory action'' under Executive Order 12866, section 3(f), and accordingly this rule has not been reviewed by the Office of Management and Budget.

Executive Order 13132

This regulation will not have substantial direct effects on the States, on the relationship between the national government and the States, or on distribution of power and responsibilities among the various levels of government. Therefore, under Executive Order 13132, we determine that this rule does not have sufficient federalism implications to warrant the preparation of a federalism assessment.

Regulatory Flexibility Act

The Director of the Bureau of Prisons, under the Regulatory Flexibility Act (5 U.S.C. 605(b)), reviewed this regulation and by approving it certifies that it will not have a significant economic impact upon a substantial number of small entities for the following reasons: This rule pertains to the correctional management of offenders committed to the custody of the Attorney General or the Director of the Bureau of Prisons, and its economic impact is limited to the Bureau's appropriated funds.

Unfunded Mandates Reform Act of 1995

This rule will not result in the expenditure by State, local and tribal governments, in the aggregate, or by the private sector, of $100,000,000 or more in any one year, and it will not significantly or uniquely affect small governments. Therefore, no actions were deemed necessary under the provisions of the Unfunded Mandates Reform Act of 1995.

Small Business Regulatory Enforcement Fairness Act of 1996

This rule is not a major rule as defined by § 804 of the Small Business Regulatory Enforcement Fairness Act of 1996. This rule will not result in an annual effect on the economy of $100,000,000 or more; a major increase in costs or prices; or significant adverse effects on competition, employment, investment, productivity, innovation, or on the ability of United States-based companies to compete with foreign-based companies in domestic and export markets.

List of Subjects in 28 CFR Part 552

Prisoners.

Harley G. Lappin,

Director, Bureau of Prisons.

■ Under the rulemaking authority vested in the Attorney General in 5 U.S.C. 552(a) and delegated to the Director, Bureau of Prisons, we amend 28 CFR part 552, chapter V, subchapter C, as follows.

SUBCHAPTER C—INSTITUTIONAL MANAGEMENT

PART 552—CUSTODY

■ 1. Revise the authority citation for 28 CFR part 552 to read as follows:

Authority: 5 U.S.C. 301; 18 U.S.C. 3621, 3622, 3624, 4001, 4042, 4081, 4082 (Repealed in part as to offenses committed on or after November 1, 1987), 5006–5024 (Repealed October 12, 1984, as to offenses committed after that date), 5039; 28 U.S.C. 509, 510.

■ 2. Revise subpart E to read as follows:

Subpart E—Suicide Prevention Program

Sec.

Subpart E—Suicide Prevention Program

§ 552.40 Purpose and scope.

The Bureau of Prisons (Bureau) operates a suicide prevention program to assist staff in identifying and managing potentially suicidal inmates. When staff identify an inmate as being at risk for suicide, staff will place the inmate on suicide watch. Based upon clinical findings, staff will either terminate the suicide watch when the inmate is no longer at imminent risk for suicide or arrange for the inmate's transfer to a medical referral center or contract health care facility.

§ 552.41 Program procedures.

(a) *Program Coordinator.* Each institution must have a Program Coordinator for the institution's suicide prevention program.

(b) *Training.* The Program Coordinator is responsible for ensuring that appropriate training is available to staff and to inmates selected as inmate observers.

(c) *Identification of at risk inmates.* (1) Medical staff are to screen a newly admitted inmate for signs that the inmate is at risk for suicide. Ordinarily, this screening is to take place within twenty-four hours of the inmate's admission to the institution.

(2) Staff (whether medical or non-medical) may make an identification at any time based upon the inmate's observed behavior.

(d) *Referral.* Staff who identify an inmate to be at risk for suicide will have the inmate placed on suicide watch.

(e) *Assessment.* A psychologist will clinically assess each inmate placed on suicide watch.

(f) *Intervention.* Upon completion of the clinical assessment, the Program Coordinator or designee will determine the appropriate intervention that best meets the needs of the inmate.

§ 552.42 Suicide watch conditions.

(a) *Housing.* Each institution must have one or more rooms designated specifically for housing an inmate on suicide watch. The designated room must allow staff to maintain adequate control of the inmate without compromising the ability to observe and protect the inmate.

(b) *Observation.* (1) Staff or trained inmate observers operating in scheduled shifts are responsible for keeping the inmate under constant observation.

(2) Only the Warden may authorize the use of inmate observers.

(3) Inmate observers are considered to be on an institution work assignment when they are on their scheduled shift.

(c) *Suicide watch log.* Observers are to document significant observed behavior in a log book.

(d) *Termination.* Based upon clinical findings, the Program Coordinator or designee will:

(1) Remove the inmate from suicide watch when the inmate is no longer at imminent risk for suicide, or

(2) Arrange for the inmate's transfer to a medical referral center or health care facility.

[FR Doc. E7–4684 Filed 3–14–07; 8:45 am]

BILLING CODE 4410–05–P

PENSION BENEFIT GUARANTY CORPORATION

29 CFR Parts 4022 and 4044

Benefits Payable in Terminated Single-Employer Plans; Allocation of Assets in Single-Employer Plans; Interest Assumptions for Valuing and Paying Benefits

AGENCY: Pension Benefit Guaranty Corporation.

ACTION: Final rule.

SUMMARY: The Pension Benefit Guaranty Corporation's regulations on Benefits Payable in Terminated Single-Employer Plans and Allocation of Assets in Single-Employer Plans prescribe interest assumptions for valuing and paying benefits under terminating single-employer plans. This final rule amends the regulations to adopt interest assumptions for plans with valuation dates in April 2007. Interest assumptions are also published on the PBGC's Web site (*http://www.pbgc.gov*).

DATES: Effective April 1, 2007.

FOR FURTHER INFORMATION CONTACT: Catherine B. Klion, Manager, Regulatory and Policy Division, Legislative and Regulatory Department, Pension Benefit Guaranty Corporation, 1200 K Street, NW., Washington, DC 20005, 202–326–4024. (TTY/TDD users may call the Federal relay service toll-free at 1–800–877–8339 and ask to be connected to 202–326–4024.)

SUPPLEMENTARY INFORMATION: The PBGC's regulations prescribe actuarial assumptions—including interest assumptions—for valuing and paying plan benefits of terminating single-employer plans covered by title IV of the Employee Retirement Income Security Act of 1974. The interest assumptions are intended to reflect current conditions in the financial and annuity markets.

Three sets of interest assumptions are prescribed: (1) A set for the valuation of benefits for allocation purposes under section 4044 (found in Appendix B to part 4044), (2) a set for the PBGC to use to determine whether a benefit is payable as a lump sum and to determine lump-sum amounts to be paid by the PBGC (found in Appendix B to part 4022), and (3) a set for private-sector pension practitioners to refer to if they wish to use lump-sum interest rates determined using the PBGC's historical methodology (found in Appendix C to part 4022).

This amendment (1) Adds to Appendix B to part 4044 the interest assumptions for valuing benefits for allocation purposes in plans with valuation dates during April 2007, (2) adds to Appendix B to part 4022 the interest assumptions for the PBGC to use for its own lump-sum payments in plans with valuation dates during April 2007, and (3) adds to Appendix C to part 4022 the interest assumptions for private-sector pension practitioners to refer to if they wish to use lump-sum interest rates determined using the PBGC's historical methodology for valuation dates during April 2007.

For valuation of benefits for allocation purposes, the interest assumptions that the PBGC will use (set forth in Appendix B to part 4044) will be 4.99 percent for the first 20 years following the valuation date and 4.66 percent thereafter. These interest assumptions represent a decrease (from those in effect for March 2007) of 0.23 percent for the first 20 years following the valuation date and 0.23 percent for all years thereafter.

The interest assumptions that the PBGC will use for its own lump-sum payments (set forth in Appendix B to part 4022) will be 2.75 percent for the period during which a benefit is in pay status and 4.00 percent during any years preceding the benefit's placement in pay status. These interest assumptions represent a decrease (from those in effect for March 2007) of 0.25 percent in the immediate annuity rate and are otherwise unchanged. For private-sector payments, the interest assumptions (set forth in Appendix C to part 4022) will be the same as those used by the PBGC for determining and paying lump sums (set forth in Appendix B to part 4022).

The PBGC has determined that notice and public comment on this amendment are impracticable and contrary to the public interest. This finding is based on the need to determine and issue new interest assumptions promptly so that the assumptions can reflect current market conditions as accurately as possible.

Because of the need to provide immediate guidance for the valuation and payment of benefits in plans with valuation dates during April 2007, the PBGC finds that good cause exists for making the assumptions set forth in this amendment effective less than 30 days after publication.

The PBGC has determined that this action is not a ''significant regulatory action'' under the criteria set forth in Executive Order 12866.

Because no general notice of proposed rulemaking is required for this amendment, the Regulatory Flexibility Act of 1980 does not apply. See 5 U.S.C. 601(2).

List of Subjects

29 CFR Part 4022

Employee benefit plans, Pension insurance, Pensions, Reporting and recordkeeping requirements.

29 CFR Part 4044

Employee benefit plans, Pension insurance, Pensions.

■ In consideration of the foregoing, 29 CFR parts 4022 and 4044 are amended as follows:

PART 4022—BENEFITS PAYABLE IN TERMINATED SINGLE-EMPLOYER PLANS

■ 1. The authority citation for part 4022 continues to read as follows:

Authority: 29 U.S.C. 1302, 1322, 1322b, 1341(c)(3)(D), and 1344.

■ 2. In appendix B to part 4022, Rate Set 162, as set forth below, is added to the table.

Appendix B to Part 4022—Lump Sum Interest Rates For PBGC Payments

* * * * *

Rate set	For plans with a valuation date		Immediate annuity rate (percent)	Deferred annuities (percent)				
	On or after	Before		i_1	i_2	i_3	n_1	n_2
*	*		*	*	*	*	*	
162	4–1–07	5–1–07	2.75	4.00	4.00	4.00	7	8

■ 3. In appendix C to part 4022, Rate Set 162, as set forth below, is added to the table.

Appendix C to Part 4022—Lump Sum Interest Rates For Private-Sector Payments

* * * * *

Rate set	For plans with a valuation date		Immediate annuity rate (percent)	Deferred annuities (percent)				
	On or after	Before		i_1	i_2	i_3	n_1	n_2
*	*		*	*	*	*	*	
162	4–1–07	5–1–07	2.75	4.00	4.00	4.00	7	8

PART 4044—ALLOCATION OF ASSETS IN SINGLE-EMPLOYER PLANS

■ 4. The authority citation for part 4044 continues to read as follows:

Authority: 29 U.S.C. 1301(a), 1302(b)(3), 1341, 1344, 1362.

■ 5. In appendix B to part 4044, a new entry for April 2007, as set forth below, is added to the table.

Appendix B to Part 4044—Interest Rates Used to Value Benefits

* * * * *

For valuation dates occurring in the month—	The values of i_t are:					
	i_t	for t =	i_t	for t =	i_t	for t =
*	*	*	*	*	*	*
April 2007	.0499	1–20	.0466	>20	N/A	N/A

Issued in Washington, DC, on this 8th day of March 2007.

Vincent K. Snowbarger,

Interim Director Pension Benefit Guaranty Corporation.

[FR Doc. E7–4680 Filed 3–14–07; 8:45 am]

BILLING CODE 7709–01–P

DEPARTMENT OF THE INTERIOR

Minerals Management Service

30 CFR Part 250

RIN 1010–AD24

Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Update of New and Reaffirmed Documents Incorporated by Reference

AGENCY: Minerals Management Service (MMS), Interior.

ACTION: Final rule.

SUMMARY: This final rule incorporates 33 new editions and 37 reaffirmed editions of documents previously incorporated by reference in regulations governing oil and gas and sulphur operations in the Outer Continental Shelf (OCS). The new and reaffirmed editions of these documents will ensure that lessees use the best and safest technologies available while operating in the OCS. The final rule also updates citations for documents that were incorporated by reference in recent final rules.

DATES: *Effective Date:* April 16, 2007. The incorporation by reference of publications listed in the regulation is approved by the Director of the Federal Register as of April 16, 2007.

FOR FURTHER INFORMATION CONTACT: Wilbon Rhome at (703) 787–1587.

SUPPLEMENTARY INFORMATION: The MMS uses standards, specifications, and recommended practices developed by standard-setting organizations and the oil and gas industry as a means of establishing requirements for activities on the OCS. This practice, known as incorporation by reference, allows us to incorporate the provisions of technical standards into the regulations. The legal effect of incorporation by reference is that the material is treated as if the entire document were published in the **Federal Register**. This material, like any other properly issued regulation, then has the force and effect of law. We hold operators/lessees accountable for complying with the documents incorporated by reference in our regulations. We currently incorporate by reference 93 private sector consensus standards into the offshore operating regulations.

The regulations at 1 CFR part 51 govern how we and other Federal agencies incorporate various documents by reference. Agencies may only incorporate a document by reference by publishing the document title and affirmation/reaffirmation date in the **Federal Register**. Agencies must also gain approval from the Director of the Federal Register for each publication incorporated by reference. Incorporation by reference of a document or publication is limited to the specific edition, supplement, or addendum cited in the regulations.

Under 5 U.S.C. 553, MMS may update documents without an opportunity for public comment when we determine that the revisions to a document result

in safety improvements, or represent new industry standard technology and do not impose undue cost or burden on the affected parties. Accordingly, this final rule incorporates the new editions of 33 documents and 37 reaffirmed documents previously incorporated by reference in regulations governing oil and gas and sulphur operations in the OCS. These new and reaffirmed documents will ensure that lessees use the best and safest technologies available while operating in the OCS.

The MMS has reviewed these documents and determined the new editions must be incorporated into the regulations to ensure the use of the best and safest technologies. Our review shows that changes between the old and new editions result in safety improvements, or represent new industry standard technology and will not impose undue cost or burden on the offshore oil and gas industry. The old editions are not readily available to the affected parties because they are out of publication; therefore, we are amending our regulations to incorporate the updated editions according to the authority in 30 CFR 250.198(a)(2). We are also amending those sections of the regulations where the title of the document has changed.

In this final rule, reaffirmed means an action taken by the API standards committee, normally within a 5-year timeframe, confirming that the information contained within the standard is still applicable and requires no change at this time. Additionally, the edition number and date of the standard does not change as a result of reaffirmation by the standards committee.

Revised Editions

The revised editions of the documents previously incorporated by reference are:

Title of documents
ANSI/AISC 360–05, Specification for Reinforced Steel Buildings, March 9, 2005.
ANSI/ASME Boiler and Pressure Vessel Code, Section I, Rules for Construction of Power Boilers; including Appendices 2004 Edition; and July 1, 2005 Addenda, Rules for Construction of Power Boilers, by ASME Boiler and Pressure Vessel Committee Subcommittee on Power Boilers; and all Section I Interpretations Volume 55.
ANSI/ASME Boiler and Pressure Vessel Code, Section IV, Rules for Construction of Heating Boilers; including Appendices 1, 2, 3, 5, 6, and Non-mandatory Appendices B, C, D, E, F, H, I, K, L, and M, and the Guide to Manufacturers Data Report Forms, 2004 Edition; July 1, 2005 Addenda, Rules for Construction of Heating Boilers, by ASME Boiler and Pressure Vessel Committee Subcommittee on Heating Boilers; and all Section IV Interpretations Volume 55.
ANSI/ASME Boiler and Pressure Vessel Code, Section VIII, Rules for Construction of Pressure Vessels; Divisions 1 and 2, 2004 Edition; July 1, 2005 Addenda, Divisions 1 and 2, Rules for Construction of Pressure Vessels, by ASME Boiler and Pressure Vessel Committee Subcommittee on Pressure Vessels; and all Section VIII Interpretations Volumes 54 and 55.
ANSI/ASME B 16.5–2003, Pipe Flanges and Flanged Fittings.
ANSI/ASME B 31.8–2003, Gas Transmission and Distribution Piping Systems.
API 510, Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair, and Alteration, Downstream Segment, Ninth Edition, June 2006, API Stock No. C51009.
API MPMS, Chapter 3-Tank Gauging, Section 1A—Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, Second Edition, August 2005, API Stock No. H301A02.
API MPMS, Chapter 3-Tank Gauging, Section 1B—Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, Second Edition, June 2001, API Stock No. H301B2.
API MPMS, Chapter 4—Proving Systems, Section 1—Introduction, Third Edition, February 2005, API Stock No. H04013.
API MPMS, Chapter 4—Proving Systems, Section 2—Displacement Provers, Third Edition, September 2003, API Stock No. H04023.
API MPMS, Chapter 4—Proving Systems, Section 4—Tank Provers, Second Edition, May 1998, API Stock No. H04042.
API MPMS, Chapter 4—Proving Systems, Section 5—Master-Meter Provers, Second Edition, May 2000, API Stock No. H04052.
API MPMS, Chapter 5—Metering, Section 1—General Considerations for Measurement by Meters, Measurement Coordination Department, Fourth Edition, September 2005, API Stock No. H05014.
API MPMS, Chapter 5—Metering, Section 2—Measurement of Liquid Hydrocarbons by Displacement Meters, Third Edition, September 2005, API Stock No. H05023.
API MPMS Chapter 5—Metering, Section 3—Measurement of Liquid Hydrocarbons by Turbine Meters, Fifth Edition, September 2005, API Stock No. H05035.
API MPMS, Chapter 5—Metering, Section 4—Accessory Equipment for Liquid Meters, Fourth Edition, September 2005, API Stock No. H05044.
API MPMS, Chapter 5—Metering, Section 5—Fidelity and Security of Flow Measurement Pulsed-Data Transmission Systems, Second Edition, August 2005, API Stock No. H50502.
API MPMS, Chapter 7—Temperature Determination, Measurement Coordination, First Edition, June 2001, API Stock No. H07001.
API MPMS, Chapter 9—Density Determination, Section 1—Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method, Second Edition, December 2002; reaffirmed October 2005, API Stock No. H09012.
API MPMS, Chapter 9—Density Determination, Section 2—Standard Test Method for Density or Relative Density of Light Hydrocarbons by Pressure Hydrometer, Second Edition, March 2003, API Stock No. H09022.
API MPMS, Chapter 10—Sediment and Water, Section 1—Standard Test Method for Sediment in Crude Oils and Fuel Oils by the Extraction Method, Second Edition, October 2002, API Stock No. H10012.
API MPMS, Chapter 10—Sediment and Water, Section 3—Standard Test Method for Water and Sediment in Crude Oil by the Centrifuge Method (Laboratory Procedure), Second Edition, May 2003, API Stock No. H10032.
API MPMS, Chapter 10—Sediment and Water, Section 4—Determination of Water and/or Sediment in Crude Oil by the Centrifuge Method (Field Procedure), Third Edition, December 1999, API Stock No. H10043.
API MPMS, Chapter 10—Sediment and Water, Section 9—Standard Test Method for Water in Crude Oils by Coulometric Karl Fischer Titration, Second Edition, December 2002; reaffirmed 2005, API Stock No. H10092.
API MPMS, Chapter 14—Natural Gas Fluids Measurement, Section 3—Concentric, Square-Edged Orifice Meters, Part 2—Specification and Installation Requirements, Fourth Edition, April 2000; reaffirmed March 2006, API Stock No. H30351.
API RP 2D, Recommended Practice for Operation and Maintenance of Offshore Cranes, Fifth Edition, June 2003, API Stock No. G02D05.
API RP 2SK, Recommended Practice for Design and Analysis of Stationkeeping Systems for Floating Structures, Third Edition, October 2005, API Stock No. G2SK03.
API RP 14B, Recommended Practice for Design, Installation, Repair and Operation of Subsurface Safety Valve Systems, Fifth Edition, October 2005, also available as ISO 10417: 2004, (Identical) Petroleum and natural gas industries—Subsurface safety valve systems—Design, installation, operation and redress, API Stock No. GX14B05.

Title of documents
API Spec. Q1, Specification for Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry, ANSI/API Specification Q1, Seventh Edition, June 15, 2003; also available as ISO/TS 29001, Effective Date: December 15, 2003, Proposed National Adoption, API Stock No. GQ1007.
API Spec. 2C, Specification for Offshore Pedestal Mounted Cranes, Sixth Edition, March 2004, Effective Date: September 2004, API Stock No. G02C06.
API Spec. 6A, Specification for Wellhead and Christmas Tree Equipment, ANSI/API Specification 6A, Nineteenth Edition, July 2004; also available as ISO 10423:2003, (Modified) Petroleum and natural gas industries—Drilling and production equipment—Wellhead and Christmas tree equipment, Effective Date: February 1, 2005; Errata 1, September 1, 2004, API Stock No. GX06A19.
API Spec. 6D, Specification for Pipeline Valves, Twenty-second Edition, January 2002; also available as ISO 14313:1999, MOD, Petroleum and natural gas industries—Pipeline transportation systems—Pipeline valves, Effective Date: July 1, 2002, Proposed National Adoption, includes Annex F, March 1, 2005, API Stock No. G06D22.

Reaffirmed Documents

The reaffirmed documents previously incorporated by reference are:

Title of documents
ACI 357R–84, Guide for the Design and Construction of Fixed Offshore Concrete Structures, 1984; reapproved 1997.
API MPMS, Chapter 2—Tank Calibration, Section 2A—Measurement and Calibration of Upright Cylindrical Tanks by the Manual Tank Strapping Method, First Edition, February 1995; reaffirmed March 2002, API Stock No. H022A1.
API MPMS, Chapter 2—Tank Calibration, Section 2B—Calibration of Upright Cylindrical Tanks Using the Optical Reference Line Method, First Edition, March 1989; reaffirmed March 2002, API Stock No. H30023.
API MPMS, Chapter 4—Proving Systems, Section 6—Pulse Interpolation, Second Edition, July 1999; reaffirmed 2003, API Stock No. H06042.
API MPMS, Chapter 4—Proving Systems, Section 7—Field Standard Test Measures, Second Edition, December 1998; reaffirmed October 2003, API Stock No. H04072.
API MPMS, Chapter 6—Metering Assemblies, Section 1—Lease Automatic Custody Transfer (LACT) Systems, Second Edition, May 1991; reaffirmed March 2002, API Stock No. H30121.
API MPMS, Chapter 6—Metering Assemblies, Section 6—Pipeline Metering Systems, Second Edition, May 1991; reaffirmed March 2002, API Stock No. H30126.
API MPMS, Chapter 6—Metering Assemblies, Section 7—Metering Viscous Hydrocarbons, Second Edition, May 1991; reaffirmed March 2002, API Stock No. H30127.
API MPMS, Chapter 8—Sampling, Section 1—Standard Practice for Manual Sampling of Petroleum and Petroleum Products, Third Edition, October 1995; reaffirmed March 2006, API Stock No. H30161.
API MPMS, Chapter 8—Sampling, Section 2—Standard Practice for Automatic Sampling of Liquid Petroleum and Petroleum Products, Second Edition, October 1995; reaffirmed June 2005, API Stock No. H08022.
API MPMS, Chapter 10—Sediment and Water, Section 2—Determination of Water in Crude Oil by the Distillation Method, First Edition, April 1981; reaffirmed 2005, API Stock No. H30202.
API MPMS, Chapter 11.1—Volume Correction Factors, Volume 1, Table 5A—Generalized Crude Oils and JP–4 Correction of Observed API Gravity to API Gravity at 60 °F, and Table 6A—Generalized Crude Oils and JP–4 Correction of Volume to 60 °F Against API Gravity at 60 °F, API Standard 2540, First Edition, August 1980; reaffirmed March 1997, API Stock No. H27000.
API MPMS, Chapter 11.2.2—Compressibility Factors for Hydrocarbons: 0.350–0.637 Relative Density (60 °F/60 °F) and −50 °F to 140 °F Metering Temperature, Second Edition, October 1986; reaffirmed December 2002, API Stock No. H27307.
API MPMS, Chapter 11—Physical Properties Data, Addendum to Section 2, Part 2—Compressibility Factors for Hydrocarbons, Correlation of Vapor Pressure for Commercial Natural Gas Liquids, First Edition, December 1994; reaffirmed December 2002, API Stock No. H27308.
API MPMS, Chapter 12—Calculation of Petroleum Quantities, Section 2—Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors, Part 1—Introduction, Second Edition, May 1995; reaffirmed March 2002, API Stock No. 852–12021.
API MPMS, Chapter 14—Natural Gas Fluids Measurement, Section 3—Concentric, Square-Edged Orifice Meters, Part 1—General Equations and Uncertainty Guidelines, Third Edition, September 1990; reaffirmed January 2003, API Stock No. H30350.
API MPMS, Chapter 14—Natural Gas Fluids Measurement, Section 3—Concentric, Square-Edged Orifice Meters, Part 3—Natural Gas Applications, Third Edition, August 1992; reaffirmed January 2003, API Stock No. H30353.
API MPMS, Chapter 14.5—Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis, Second Edition, revised 1996; reaffirmed March 2002, API Stock No. H14052.
API MPMS, Chapter 14—Natural Gas Fluids Measurement, Section 6—Continuous Density Measurement, Second Edition, April 1991; reaffirmed February 2006, API Stock No. H30346.
API MPMS, Chapter 14—Natural Gas Fluids Measurement, Section 8—Liquefied Petroleum Gas Measurement, Second Edition, July 1997; reaffirmed March 2002, API Stock No. H14082.
API MPMS, Chapter 20—Section 1—Allocation Measurement, First Edition, August 1993; reaffirmed October 2006, API Stock No. H30701.
API MPMS, Chapter 21—Flow Measurement Using Electronic Metering Systems, Section 1—Electronic Gas Measurement, First Edition, August 1993; reaffirmed July 2005, API Stock No. H30730.
API RP 2A–WSD, Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms—Working Stress Design, Twenty-first Edition, December 2000; Errata and Supplement 1, December 2002; Errata and Supplement 2, October 2005, API Stock No. G2AWSD.
API RP 14E, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems, Fifth Edition, October 1, 1991; reaffirmed June 2000, API Stock No. G07185.
API RP 14G, Recommended Practice for Fire Prevention and Control on Open Type Offshore Production Platforms, Third Edition, December 1, 1993; reaffirmed June 2000, API Stock No. G07194.
API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells, Third Edition, March 1997; reaffirmed September 2004, API Stock No. G53003.

Title of documents
API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2, Second Edition, November 1997; reaffirmed November 2002, API Stock No. C50002.
API RP 505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2, First Edition, November 1997; reaffirmed November 2002, API Stock No. C50501.
API RP 2556, Recommended Practice for Correcting Gauge Tables for Incrustation, Second Edition, August 1993; reaffirmed November 2003, API Stock No. H25560.
API Spec. 6AV1, Specification for Verification Test of Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service, First Edition, February 1, 1996; reaffirmed January 2003, API Stock No. G06AV1.
API Standard 2551, Measurement and Calibration of Horizontal Tanks, First Edition, 1965; reaffirmed March 2002, API Stock No. H25510.
API Standard 2552, USA Standard Method for Measurement and Calibration of Spheres and Spheroids, first Edition, 1966; reaffirmed February 2006, API Stock No. H25520.
API Standard 2555, Method for Liquid Calibration of Tanks, First Edition, September 1966; reaffirmed March 2002; API Stock No. H25550.
AWS D1.1:2000, Structural Welding Code—Steel.
AWS D3.6M:1999, Specification for Underwater Welding.
NACE Standard MR0175–2003, Item No. 21302, Standard Material Requirements, Metals for Sulfide Stress Cracking and Stress Corrosion Cracking Resistance in Sour Oilfield Environments.
NACE Standard RP0176–2003, Item No. 21018, Standard Recommended Practice, Corrosion Control of Steel Fixed Offshore Structures Associated with Petroleum Production.

Withdrawn Documents

Some documents were combined as follows: API MPMS Chapter 4, sections 2 and 3 were combined; API MPMS Chapter 7, sections 2 and 3 were combined; and API MPMS Chapters 11.2.1 and 11.2.3 were combined. MMS is withdrawing six documents and replacing them with three documents as follows:

Title of documents withdrawn	Title of replacing documents
API MPMS, Chapter 4, Section 2, Conventional Pipe Provers, Third Edition, September 2003, API Stock No. H30082.	API MPMS, Chapter 4—Proving Systems, Section 2—Displacement Provers, Third Edition, September 2003, API Stock No. H04023.
API MPMS, Chapter 4, Section 3, Small Volume Provers, First Edition, July 1988, reaffirmed March 2002, API Stock No. H30083.	
API MPMS, Chapter 7, Temperature Determination, Section 2, Dynamic Temperature Determination, Second Edition, March 1995, API Stock No. H07022.	API MPMS, Chapter 7—Temperature Determination, Measurement Coordination, First Edition, June 2001, API Stock No. H07001.
API MPMS, Chapter 7, Section 3, Static Temperature Determination Using Portable Electronic Thermometers, First Edition, July 1985, reaffirmed May 1996, API Stock No. H30143.	
API MPMS, Chapter 11.2.1, Compressibility Factors for Hydrocarbons: 0–90° API Gravity Range, First Edition, August 1984; reaffirmed May 1996, API Stock No. H27300.	MPMS Measurement Standards Chapter 11.1, Volume Correction Factors, Volume 1 * * * First Edition, August 1980; reaffirmed March 1997, API Stock No. H27000.
API MPMS, Chapter 11.2.3, Water Calibration of Volumetric Provers, First Edition, August 1984; reaffirmed May 1996, API Stock No. H27310.	

The purpose of this final rule is to incorporate the revision of some documents previously incorporated by reference into MMS regulations, and to acknowledge the reaffirmation of other documents previously incorporated by reference into MMS regulations.

Procedural Matters

Regulatory Planning and Review (Executive Order (E.O.) 12866)

This final rule is not a significant rule as determined by the Office of Management and Budget (OMB) and is not subject to review under E.O. 12866.

(1) The final rule will not have an annual effect of $100 million or more on the economy. It will not adversely affect in a material way the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities. This final rule will not have any new requirements.

(2) The final rule will not create a serious inconsistency or otherwise interfere with an action taken or planned by another agency because it does not affect how lessees or operators interact with other agencies, nor does it affect how MMS will interact with other agencies.

(3) The final rule will not alter the budgetary effects or entitlements, grants, user fees, or loan programs, or the rights or obligations of their recipients. The changes in this final rule will not impose undue cost on the offshore oil and gas industry.

(4) The final rule will not raise novel legal or policy issues.

Regulatory Flexibility Act (RFA)

The Department certifies that this final rule will not have a significant economic effect on a substantial number of small entities under the RFA (5 U.S.C. 601 *et seq.*).

The changes proposed in this final rule would affect lessees and operators of leases and pipeline right-of-way holders on the OCS. This could include about 130 active Federal oil and gas lessees. Small lessees that operate under this rule fall under the Small Business Administration's (SBA) North American Industry Classification System (NAICS) codes 211111, Crude Petroleum and Natural Gas Extraction, and 213111, Drilling Oil and Gas Wells. For these NAICS code classifications, a small company is one with fewer than 500 employees. Based on these criteria, an estimated 70 percent of these companies are considered small. This final rule, therefore would affect a substantial number of small entities.

The changes proposed in the rule will not have a significant economic effect on a substantial number of small entities because it will not impose undue cost

or burden on the offshore oil and gas industry.

Your comments are important. The Small Business and Agriculture Regulatory Enforcement Ombudsman and 10 Regional Fairness boards were established to receive comments from small businesses about Federal agency enforcement actions. The Ombudsman will annually evaluate the enforcement activities and rate each agency's responsiveness to small businesses. If you wish to comment on the actions of MMS, call 1–888–734–3247. You may comment to the Small Business Administration without fear of retaliation. Disciplinary action for retaliation by an MMS employee may include suspension or termination from employment with the DOI.

Small Business Regulatory Enforcement Fairness Act (SBREFA)

This final rule is not a major rule under the SBREFA (5 U.S.C. 804(2)). This final rule:

a. Will not have an annual effect on the economy of $100 million or more. The only costs will be the purchase of the new document and minor revisions to some operating and maintenance procedures.

b. Will not cause a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions.

c. Will not have significant adverse effects on competition, employment, investment, productivity, innovation, or the ability of U.S.-based enterprises to compete with foreign-based enterprises. Leasing on the U.S. OCS is limited to residents of the U.S. or companies incorporated in the U.S. This final rule will not change that requirement.

Unfunded Mandates Reform Act (UMRA)

This final rule will not impose an unfunded mandate on State, local, and tribal governments or the private sector of more than $100 million per year. The rule will not have a significant or unique effect on State, local, or tribal governments or the private sector. A statement containing the information required by the UMRA (2 U.S.C. 1531 *et seq.*) is not required. This is because the rule will not affect State, local, or tribal governments, and the effect on the private sector is small.

Takings Implication Assessment (Executive Order 12630)

This final rule is not a governmental action capable of interference with constitutionally protected property rights. Thus, MMS did not need to prepare a Takings Implication Assessment according to E.O. 12630, Governmental Actions and Interference with Constitutionally Protected Property Rights.

Federalism (Executive Order 13132)

With respect to E.O. 13132, this final rule will not have federalism implications. This rule will not substantially and directly affect the relationship between the Federal and State governments. To the extent that State and local governments have a role in OCS activities, this rule will not affect that role.

Civil Justice Reform (Executive Order 12988)

With respect to E.O. 12988, the Office of the Solicitor has determined that the final rule will not unduly burden the judicial system and will meet the requirements of sections 3(a) and 3(b)(2) of the Order.

Paperwork Reduction Act (PRA) of 1995

The Department of the Interior has determined that this regulation does not contain information collection requirements pursuant to PRA (44 U.S.C. 3501 *et seq.*). The MMS will not be submitting an information collection request to OMB.

National Environmental Policy Act (NEPA) of 1969

This rule does not constitute a major Federal action significantly affecting the quality of the human environment. MMS has analyzed this rule under the criteria of the NEPA and 516 Departmental Manual 6, Appendix 10.4C(1). MMS completed a Categorical Exclusion Review for this action and concluded that ''the rulemaking does not represent an exception to the established criteria for categorical exclusion; therefore, preparation of an environmental analysis or environmental impact statement will not be required.''

Energy Supply, Distribution, or Use (Executive Order 13211)

Executive Order 13211 requires the agency to prepare a Statement of Energy Effects when it takes a regulatory action that is identified as a significant energy action. This rule is not a significant energy action, and therefore will not require a Statement of Energy Effects, because it:

a. Is not a significant regulatory action under E.O. 12866,

b. Is not likely to have a significant adverse effect on the supply, distribution, or use of energy, and

c. Has not been designated by the Administrator of the Office of Information and Regulatory Affairs, OMB, as a significant energy action.

Consultation with Indian Tribes (Executive Order 13175)

Under the criteria in E.O. 13175, we have evaluated this rule and determined that it has no potential effects on federally recognized Indian tribes. There are no Indian or tribal lands on the OCS.

List of Subjects in 30 CFR Part 250

Continental shelf, Environmental impact statements, Environmental protection, Government contracts, Incorporation by reference, Investigations, Oil and gas exploration, Penalties, Pipelines, Public lands—mineral resources, Public lands—rights-of-way, Reporting and recordkeeping requirements.

Dated: February 5, 2007.

C. Stephen Allred,

Assistant Secretary—Land and Minerals Management.

■ For the reasons stated in the preamble, Minerals Management Service (MMS) amends 30 CFR part 250 as follows:

PART 250—OIL AND GAS AND SULPHUR OPERATIONS IN THE OUTER CONTINENTAL SHELF

■ 1. The authority citation for Part 250 continues to read as follows:

Authority: 43 U.S.C. 1331 *et seq.*, 31 U.S.C. 9701.

■ 2. In § 250.108, revise paragraph (c) to read as follows:

§ 250.108 What requirements must I follow for cranes and other material-handling equipment?

* * * * *

(c) If a fixed platform is installed after March 17, 2003, all cranes on the platform must meet the requirements of American Petroleum Institute Specification for Offshore Pedestal Mounted Cranes (API Spec 2C), incorporated by reference as specified in 30 CFR 250.198.

* * * * *

■ 3. In § 250.198, revise the table in paragraph (e) to read as follows:

§ 250.198 Documents incorporated by reference.

* * * * *

(e) * * *

Title of documents	Incorporated by reference at
ACI Standard 318–95, Building Code Requirements for Reinforced Concrete (ACI 318–95) and Commentary (ACI 318R–95).	§ 250.901(a)(1).
ACI 357R–84, Guide for the Design and Construction of Fixed Offshore Concrete Structures, 1984; reapproved 1997.	§ 250.901(a)(2).
ANSI/AISC 360–05, Specification for Structural Steel Buildings, March 9, 2005	§ 250.901(a)(3).
ANSI/ASME Boiler and Pressure Vessel Code, Section I, Rules for Construction of Power Boilers; including Appendices 2004 Edition; and July 1, 2005 Addenda, Rules for Construction of Power Boilers, by ASME Boiler and Pressure Vessel Committee Subcommittee on Power Boilers; and all Section I Interpretations Volume 55.	§ 250.803(b)(1), (b)(1)(i); § 250.1629(b)(1), (b)(1)(i).
ANSI/ASME Boiler and Pressure Vessel Code, Section IV, Rules for Construction of Heating Boilers; including Appendices 1, 2, 3, 5, 6, and Non-mandatory Appendices B, C, D, E, F, H, I, K, L, and M, and the Guide to Manufacturers Data Report Forms, 2004 Edition; July 1, 2005 Addenda, Rules for Construction of Heating Boilers, by ASME Boiler and Pressure Vessel Committee Subcommittee on Heating Boilers; and all Section IV Interpretations Volume 55.	§ 250.803(b)(1), (b)(1)(i); § 250.1629(b)(1), (b)(1)(i).
ANSI/ASME Boiler and Pressure Vessel Code, Section VIII, Rules for Construction of Pressure Vessels; Divisions 1 and 2, 2004 Edition; July 1, 2005 Addenda, Divisions 1 and 2, Rules for Construction of Pressure Vessels, by ASME Boiler and Pressure Vessel Committee Subcommittee on Pressure Vessels; and all Section VIII Interpretations Volumes 54 and 55.	§ 250.803(b)(1), (b)(1)(i); § 250.1629(b)(1), (b)(1)(i).
ANSI/ASME B 16.5–2003, Pipe Flanges and Flanged Fittings	§ 250.1002(b)(2).
ANSI/ASME B 31.8–2003, Gas Transmission and Distribution Piping Systems	§ 250.1002(a).
ANSI/ASME SPPE–1–1994 and SPPE–1d–1996 Addenda, Quality Assurance and Certification of Safety and Pollution Prevention Equipment Used in Offshore Oil and Gas Operations.	§ 250.806(a)(2)(i).
ANSI Z88.2–1992, American National Standard for Respiratory Protection	§ 250.490(g)(4)(iv), (j)(13)(ii).
API 510, Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair, and Alteration, Downstream Segment, Ninth Edition, June 2006, API Stock No. C51009.	§ 250.803(b)(1); § 250.1629(b)(1).
API MPMS, Chapter 1—Vocabulary, Second Edition, July 1994, API Stock No. H01002	§ 250.1201.
API MPMS, Chapter 2—Tank Calibration, Section 2A—Measurement and Calibration of Upright Cylindrical Tanks by the Manual Tank Strapping Method, First Edition, February 1995; reaffirmed March 2002, API Stock No. H022A1.	§ 250.1202(l)(4).
API MPMS, Chapter 2—Tank Calibration, Section 2B—Calibration of Upright Cylindrical Tanks Using the Optical Reference Line Method, First Edition, March 1989; reaffirmed March 2002, API Stock No. H30023.	§ 250.1202(l)(4).
API MPMS, Chapter 3—Tank Gauging, Section 1A—Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, Second Edition, August 2005, API Stock No. H301A02.	§ 250.1202(l)(4).
API MPMS, Chapter 3—Tank Gauging, Section 1B—Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, Second Edition, June 2001, API Stock No. H301B2.	§ 250.1202(l)(4).
API MPMS, Chapter 4—Proving Systems, Section 1—Introduction, Third Edition, February 2005, API Stock No. H04013.	§ 250.1202(a)(3), (f)(1).
API MPMS, Chapter 4—Proving Systems, Section 2—Displacement Provers, Third Edition, September 2003, API Stock No. H04023.	§ 250.1202(a)(3), (f)(1).
API MPMS, Chapter 4—Proving Systems, Section 4—Tank Provers, Second Edition, May 1998, API Stock No. H04042.	§ 250.1202(a)(3), (f)(1).
API MPMS, Chapter 4—Proving Systems, Section 5—Master-Meter Provers, Second Edition, May 2000, API Stock No. H04052.	§ 250.1202(a)(3), (f)(1).
API MPMS, Chapter 4—Proving Systems, Section 6—Pulse Interpolation, Second Edition, July 1999; reaffirmed 2003, API Stock No. H06042.	§ 250.1202(a)(3), (f)(1).
API MPMS, Chapter 4—Proving Systems, Section 7—Field Standard Test Measures, Second Edition, December 1998; reaffirmed 2003, API Stock No. H04072.	§ 250.1202(a)(3), (f)(1).
API MPMS, Chapter 5—Metering, Section 1—General Considerations for Measurement by Meters, Measurement Coordination Department, Fourth Edition, September 2005, API Stock No. H05014.	§ 250.1202(a)(3).
API MPMS, Chapter 5—Metering, Section 2—Measurement of Liquid Hydrocarbons by Displacement Meters, Third Edition, September 2005, API Stock No. H05023.	§ 250.1202(a)(3).
API MPMS Chapter 5—Metering, Section 3—Measurement of Liquid Hydrocarbons by Turbine Meters, Fifth Edition, September 2005, API Stock No. H05035.	§ 250.1202(a)(3).
API MPMS, Chapter 5—Metering, Section 4—Accessory Equipment for Liquid Meters, Fourth Edition, September 2005, API Stock No. H05044.	§ 250.1202(a)(3).
API MPMS, Chapter 5—Metering, Section 5—Fidelity and Security of Flow Measurement Pulsed-Data Transmission Systems, Second Edition, August 2005, API Stock No. H50502.	§ 250.1202(a)(3).
API MPMS, Chapter 6—Metering Assemblies, Section 1—Lease Automatic Custody Transfer (LACT) Systems, Second Edition, May 1991; reaffirmed March 2002, API Stock No. H30121.	§ 250.1202(a)(3).
API MPMS, Chapter 6—Metering Assemblies, Section 6—Pipeline Metering Systems, Second Edition, May 1991; reaffirmed March 2002, API Stock No. H30126.	§ 250.1202(a)(3).
API MPMS, Chapter 6—Metering Assemblies, Section 7—Metering Viscous Hydrocarbons, Second Edition, May 1991; reaffirmed March 2002, API Stock No. H30127.	§ 250.1202(a)(3).
API MPMS, Chapter 7—Temperature Determination, Measurement Coordination, First Edition, June 2001, API Stock No. H07001.	§ 250.1202(a)(3), (l)(4).
API MPMS, Chapter 8—Sampling, Section 1—Standard Practice for Manual Sampling of Petroleum and Petroleum Products, Third Edition, October 1995; reaffirmed March 2006, API Stock No. H30161.	§ 250.1202(b)(4)(i), (l)(4).

Title of documents	Incorporated by reference at
API MPMS, Chapter 8—Sampling, Section 2—Standard Practice for Automatic Sampling of Liquid Petroleum and Petroleum Products, Second Edition, October 1995; reaffirmed June 2005, API Stock No. H08022.	§ 250.1202(a)(3), (l)(4).
API MPMS, Chapter 9—Density Determination, Section 1—Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method, Second Edition, December 2002; reaffirmed October 2005, API Stock No. H09012.	§ 250.1202(a)(3), (l)(4).
API MPMS, Chapter 9—Density Determination, Section 2—Standard Test Method for Density or Relative Density of Light Hydrocarbons by Pressure Hydrometer, Second Edition, March 2003, API Stock No. H09022.	§ 250.1202(a)(3), (l)(4).
API MPMS, Chapter 10—Sediment and Water, Section 1—Standard Test Method for Sediment in Crude Oils and Fuel Oils by the Extraction Method, Second Edition, October 2002, API Stock No. H10012.	§ 250.1202(a)(3), (l)(4).
API MPMS, Chapter 10—Sediment and Water, Section 2—Determination of Water in Crude Oil by Distillation Method, First Edition, April 1981; reaffirmed 2005, API Stock No. H30202.	§ 250.1202(a)(3), (l)(4).
API MPMS, Chapter 10—Sediment and Water, Section 3—Standard Test Method for Water and Sediment in Crude Oil by the Centrifuge Method (Laboratory Procedure), Second Edition, May 2003, API Stock No. H10032.	§ 250.1202(a)(3), (l)(4).
API MPMS, Chapter 10—Sediment and Water, Section 4—Determination of Water and/or Sediment in Crude Oil by the Centrifuge Method (Field Procedure), Third Edition, December 1999, API Stock No. H10043.	§ 250.1202(a)(3), (l)(4).
API MPMS, Chapter 10—Sediment and Water, Section 9—Standard Test Method for Water in Crude Oils by Coulometric Karl Fischer Titration, Second Edition, December 2002; reaffirmed 2005, API Stock No. H10092.	§ 250.1202(a)(3), (l)(4).
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API MPMS, Chapter 11.2.2—Compressibility Factors for Hydrocarbons: 0.350–0.637 Relative Density (60°F/60°F) and −50°F to 140°F Metering Temperature, Second Edition, October 1986; reaffirmed December 2002, API Stock No. H27307.	§ 250.1202(a)(3), (g)(4).
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API MPMS, Chapter 12—Calculation of Petroleum Quantities, Section 2—Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors, Part 1—Introduction, Second Edition, May 1995; reaffirmed March 2002, API Stock No. 852–12021.	§ 250.1202(a)(3), (g)(1), (g)(2).
API MPMS, Chapter 12—Calculation of Petroleum Quantities, Section 2—Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors, Part 2—Measurement Tickets, Third Edition, June 2003, API Stock No. H12223.	§ 250.1202(a)(3), (g)(1), (g)(2)
API MPMS, Chapter 14—Natural Gas Fluids Measurement, Section 3—Concentric, Square-Edged Orifice Meters, Part 1—General Equations and Uncertainty Guidelines, Third Edition, September 1990; reaffirmed January 2003, API Stock No. H30350.	§ 250.1203(b)(2).
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API MPMS, Chapter 20—Section 1—Allocation Measurement, First Edition, August 1993; reaffirmed October 2006, API Stock No. H30701.	§ 250.1202(k)(1).
API MPMS, Chapter 21—Flow Measurement Using Electronic Metering Systems, Section 1—Electronic Gas Measurement, First Edition, August 1993; reaffirmed July 2005, API Stock No. H30730.	§ 250.1203(b)(4).
API RP 2A–WSD, Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms—Working Stress Design, Twenty-first Edition, December 2000; Errata and Supplement 1, December 2002; Errata and Supplement 2, October 2005, API Stock No. G2AWSD.	§ 250.901(a)(4); § 250.908(a); § 250.920(a), (b), (c), (e).
API RP 2D, Recommended Practice for Operation and Maintenance of Offshore Cranes, Fifth Edition, June 2003, API Stock No. G02D05.	§ 250.108(a).
API RP 2FPS, Recommended Practice for Planning, Designing, and Constructing Floating Production Systems, First Edition, March 2001, API Stock No. G2FPS1.	§ 250.901(a)(5).

Title of documents	Incorporated by reference at
API RP 2RD, Recommended Practice for Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs), First Edition, June 1998; reaffirmed May 2006, API Stock No. G02RD1.	§ 250.800(b)(2); § 250.901(a)(6); § 250.1002(b)(5).
API RP 2SK, Recommended Practice for Design and Analysis of Stationkeeping Systems for Floating Structures, Third Edition, October 2005, API Stock No. G2SK03.	§ 250.800(b)(3); § 250.901(a)(7).
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API RP 14B, Recommended Practice for Design, Installation, Repair and Operation of Subsurface Safety Valve Systems, Fifth Edition, October 2005, also available as ISO 10417: 2004, (Identical) Petroleum and natural gas industries—Subsurface safety valve systems—Design, installation, operation and redress, API Stock No. GX14B05.	§ 250.801(e)(4); § 250.804(a)(1)(i).
API RP 14C, Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms, Seventh Edition, March 2001, API Stock No. C14C07.	§ 250.125(a); § 250.292(j); § 250.802(b), (e)(2); § 250.803(a), (b)(2)(i), (b)(4), (b)(5)(i), (b)(7), (b)(9)(v), (c)(2); § 250.804(a), (a)(6); § 250.1002(d); § 250.1004(b)(9); § 250.1628(c), (d)(2); § 250.1629(b)(2), (b)(4)(v); § 250.1630(a).
API RP 14E, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems, Fifth Edition, October 1, 1991; reaffirmed June 2000, API Stock No. G07185.	§ 250.802(e)(3); § 250.1628(b)(2), (d)(3).
API RP 14F, Recommended Practice for Design and Installation of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class I, Division 1 and Division 2 Locations, Fourth Edition, June 1999, API Stock No. G14F04.	§ 250.114(c); § 250.803(b)(9)(v); § 250.1629(b)(4)(v).
API RP 14FZ, Recommended Practice for Design and Installation of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class I, Zone 0, Zone 1 and Zone 2 Locations, First Edition, September 2001, API Stock No. G14FZ1.	§ 250.114(c); § 250.803(b)(9)(v); § 250.1629(b)(4)(v).
API RP 14G, Recommended Practice for Fire Prevention and Control on Open Type Offshore Production Platforms, Third Edition, December 1, 1993; reaffirmed June 2000, API Stock No. G07194.	§ 250.803(b)(8), (b)(9)(v); § 250.1629(b)(3), (b)(4)(v).
API RP 14H, Recommended Practice for Installation, Maintenance, and Repair of Surface Safety Valves and Underwater Safety Valves Offshore, Fourth Edition, July 1, 1994, API Stock No. G14H04.	§ 250.802(d); § 250.804(a)(5).
API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities, Second Edition, May 2001, API Stock No. G14J02.	§ 250.800(b)(1); § 250.901(a)(10).
API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells, Third Edition, March 1997; reaffirmed September 2004, API Stock No. G53003.	§ 250.442(c); § 250.446(a).
API RP 65, Recommended Practice for Cementing Shallow Water Flow Zones in Deep Water Wells, First Edition, September 2002, API Stock No. G56001.	§ 250.198; § 250.415(e).
API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2, Second Edition, November 1997; reaffirmed November 2002, API Stock No. C50002.	§ 250.114(a); § 250.459; § 250.802(e)(4)(i); § 250.803(b)(9)(i); § 250.1628(b)(3), (d)(4)(i); § 250.1629(b)(4)(i).
API RP 505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2, First Edition, November 1997; reaffirmed November 2002, API Stock No. C50501.	§ 250.114(a); § 250.459; § 250.802(e)(4)(i); § 250.803(b)(9)(i); § 250.1628(b)(3), (d)(4)(i); § 250.1629(b)(4)(i).
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API Spec. Q1, Specification for Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry, ANSI/API Specification Q1, Seventh Edition, June 15, 2003; also available as ISO/TS 29001, Effective Date: December 15, 2003, API Stock No. GQ1007.	§ 250.806(a)(2)(ii).
API Spec. 2C, Specification for Offshore Pedestal Mounted Cranes, Sixth Edition, March 2004, Effective Date: September 2004, API Stock No. G02C06.	§ 250.108(c), (d).
API Spec. 6A, Specification for Wellhead and Christmas Tree Equipment, ANSI/API Specification 6A, Nineteenth Edition, July 2004; also available as ISO 10423:2003, (Modified) Petroleum and natural gas industries—Drilling and production equipment—Wellhead and Christmas tree equipment, Effective Date: February 1, 2005; Errata 1, September 1, 2004, API Stock No. GX06A19.	§ 250.806(a)(3); § 250.1002 (b)(1), (b)(2).
API Spec. 6AV1, Specification for Verification Test of Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service, First Edition, February 1, 1996; reaffirmed January 2003, API Stock No. G06AV1.	§ 250.806(a)(3).
API Spec. 6D, Specification for Pipeline Valves, Twenty-second Edition, January 2002; also available as ISO 14313:1999, MOD, Petroleum and natural gas industries—Pipeline transportation systems—Pipeline valves, Effective Date: July 1, 2002, Proposed National Adoption, includes Annex F, March 1, 2005, API Stock No. G06D22.	§ 250.1002(b)(1).
API Spec. 14A, Specification for Subsurface Safety Valve Equipment, Tenth Edition, November 2000; also available as ISO 10432:1999, Petroleum and natural gas industries—Downhole equipment—Subsurface safety valve equipment, Effective Date: May 15, 2001, API Stock No. GG14A10.	§ 250.806(a)(3).
API Spec. 17J, Specification for Unbonded Flexible Pipe, Second Edition, November 1999; Errata dated May 25, 2001; Addendum 1, June 2003, Effective Date: December 2002, API Stock No. G17J02.	§ 250.803(b)(2)(iii); § 250.1002(b)(4); § 250.1007(a)(4).

Title of documents	Incorporated by reference at
API Standard 2551, Measurement and Calibration of Horizontal Tanks, First Edition, 1965; reaffirmed March 2002, API Stock No. H25510.	§ 250.1202(l)(4).
API Standard 2552, USA Standard Method for Measurement and Calibration of Spheres and Spheroids, First Edition, 1966; reaffirmed February 2006, API Stock No. H25520.	§ 250.1202(l)(4).
API Standard 2555, Method for Liquid Calibration of Tanks, First Edition, September 1966; reaffirmed March 2002; API Stock No. H25550.	§ 250.1202(l)(4).
ASTM Standard C 33–99a, Standard Specification for Concrete Aggregates	§ 250.901(a)(11).
ASTM Standard C 94/C 94M–99, Standard Specification for Ready-Mixed Concrete	§ 250.901(a)(12).
ASTM Standard C 150–99, Standard Specification for Portland Cement	§ 250.901(a)(13).
ASTM Standard C 330–99, Standard Specification for Lightweight Aggregates for Structural Concrete.	§ 250.901(a)(14).
ASTM Standard C 595–98, Standard Specification for Blended Hydraulic Cements	§ 250.901(a)(15).
AWS D1.1:2000, Structural Welding Code—Steel	§ 250.901(a)(16).
AWS D1.4–98, Structural Welding Code—Reinforcing Steel	§ 250.901(a)(17).
AWS D3.6M:1999, Specification for Underwater Welding	§ 250.901(a)(18).
NACE Standard MR0175–2003, Item No. 21302, Standard Material Requirements, Metals for Sulfide Stress Cracking and Stress Corrosion Cracking Resistance in Sour Oilfield Environments.	§ 250.901(a)(19), § 250.490(p)(2).
NACE Standard RP0176–2003, Item No. 21018, Standard Recommended Practice, Corrosion Control of Steel Fixed Offshore Structures Associated with Petroleum Production.	§ 250.901(a)(20).

■ 4. Section 250.490(p)(2) is revised to read as follows:

§ 250.490 Hydrogen sulfide.

* * * * *

(p) * * *

(2) Use BOP system components, wellhead, pressure-control equipment, and related equipment exposed to H^2S-bearing fluids in conformance with NACE Standard MR0175–03 (incorporated by reference as specified in § 250.198).

■ 5. In § 250.801, revise paragraph (e)(4) to read as follows:

§ 250.801 Subsurface safety devices.

* * * * *

(e) * * *

(4) All SSSV's must be inspected, installed, maintained, and tested in accordance with American Petroleum Institute Recommended Practice 14B, Recommended Practice for Design, Installation, Repair, and Operation of Subsurface Safety Valve Systems (incorporated by reference as specified in § 250.198).

* * * * *

■ 6. In § 250.802, paragraph (d), the first sentence is revised to read as follows:

§ 250.802 Design, installation, and operation of surface production-safety systems.

* * * * *

(d) *Use of SSVs and USVs.* All SSVs and USVs must be inspected, installed, maintained, and tested in accordance with API RP 14H, Recommended Practice for Installation, Maintenance, and Repair of Surface Safety Valves and Underwater Safety Valves Offshore (incorporated by reference as specified in § 250.198). * * *

* * * * *

■ 7. In § 250.803, revise the last sentence in paragraph (b)(1), to read as follows:

§ 250.803 Additional production system requirements.

* * * * *

(b) * * *

(1) * * * Pressure and fired vessels must have maintenance inspection, rating, repair, and alteration performed in accordance with the applicable provisions of API Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair, and Alteration, API 510 (except Sections 6.5 and 8.5) (incorporated by reference as specified in § 250.198).

* * * * *

■ 8. In § 250.806, revise paragraph (a)(2)(ii) to read as follows:

§ 250.806 Safety and pollution prevention equipment quality assurance requirements.

(a) * * *

(2) * * *

(ii) API Spec Q1, Specification for Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry (incorporated by reference as specified in § 250.198).

* * * * *

■ 9. In § 250.901, revise paragraph (a)(3) to read as follows:

§ 250.901 What industry standard must your platform meet?

(a) * * *

(3) ANSI/AISC 360–05, Specification for Structural Steel Buildings, (incorporated by reference as specified in § 250.198);

* * * * *

■ 10. In § 250.1002, paragraph (a) is amended by revising the first sentence following the formula and (b)(2) is amended by revising the first sentence to read as follows:

§ 250.1002 Design requirements for DOI pipelines.

(a) * * * For limitations see section 841.121 of American National Standards Institute (ANSI) B31.8 (incorporated by reference as specified in 30 CFR 250.198) where—* * *

(b)(1)* * *

(2) Pipeline flanges and flange accessories shall meet the minimum design requirements of ANSI B16.5, API Spec 6A, or the equivalent (incorporated by reference as specified in 30 CFR 250.198). * * *

* * * * *

■ 11. In § 250.1629, revise the last sentence in paragraph (b) to read as follows:

§ 250.1629 Additional production and fuel gas system requirements.

* * * * *

(b) * * * Pressure and fired vessels must have maintenance inspection, rating, repair, and alteration performed in accordance with the applicable provisions of the American Petroleum Institute's Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair, and Alteration, API 510 (except §§ 6.5 and 8.5) (incorporated by reference as specified in § 250.198).

* * * * *

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DEPARTMENT OF COMMERCE

National Telecommunications and Information Administration

47 CFR Part 301

[Docket Number: 0612242667—7051—01]

RIN 0660–AA16

Rules to Implement and Administer a Coupon Program for Digital-to-Analog Converter Boxes

AGENCY: National Telecommunications and Information Administration, Commerce.

ACTION: Final rule.

SUMMARY: In this document, the National Telecommunications and Information Administration (NTIA) adopts regulations to implement and administer a coupon program for digital-to-analog converter boxes. This rule implements provisions of section 3005 of Public Law 109–171, known as the Digital Television Transition and Public Safety Act of 2005. This action amends 47 CFR Chapter III by adding part 301.

DATES: These rules become effective April 16, 2007.

ADDRESSES: A complete set of comments filed in response to the Notice of Proposed Rulemaking is available for public inspection at the Office of the Chief Counsel, National Telecommunications and Information Administration, Room 4713, U.S. Department of Commerce, 1401 Constitution Avenue, N.W., Washington, D.C. The responses can also be viewed electronically at http://www.ntia.doc.gov.

FOR FURTHER INFORMATION CONTACT: Milton Brown, NTIA (202) 482–1816.

SUPPLEMENTARY INFORMATION:

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I. Background

1. The Digital Television Transition and Public Safety Act of 2005 (the Act), among other things, directs the Federal Communications Commission (FCC) to require full-power television stations to cease analog broadcasting and to broadcast solely digital transmissions after February 17, 2009.[1] The returned analog television spectrum is to be auctioned, and the Act directs the FCC to deposit receipts from that auction into a new Treasury Fund to be known as the Digital Television Transition and Public Safety Fund (the Fund).[2]

2. Recognizing that consumers may wish to continue receiving broadcast programming over the air using analog-only televisions not connected to cable or satellite service, the Act authorizes NTIA to create a digital-to-analog converter box assistance program (Coupon Program). Specifically, Section 3005 of the Act directs NTIA to implement and administer a program through which eligible U.S. households may obtain via the United States Postal Service a maximum of two coupons of $40 each to be applied towards the purchase of a Coupon-Eligible Converter Box (CECB).[3] To implement the Coupon Program, the Act authorizes NTIA to use up to $990 million from the Fund for the program, including up to $100 million for program administration (Initial Funds).[4] A contingent level of $510 million in additional funds is authorized upon a 60-day notice and certification to the Committee on Energy and Commerce of the House of Representatives and the Committee on Commerce, Science, and Transportation of the Senate that the initial funding level is insufficient to fulfill coupon requests for eligible U.S. households (Contingent Funds).[5] NTIA is, therefore, authorized to expend up to a total of $1.5 billion for the program, including up to $160 million for administration. Assuming the entire administrative amount is taken into account, $1.34 billion would be available for distributing up to 33.5 million coupons. This section also authorizes NTIA, beginning on October 1, 2006, to borrow not more than $1.5 billion from the Treasury to implement the program. NTIA must reimburse the Treasury for this amount, without interest, as recovered analog television spectrum auction proceeds are deposited into the Fund.[6]

3. On July 25, 2006, NTIA published a Notice of Proposed Rulemaking (NPRM) and Request for Comment in the **Federal Register** on ways to implement and administer such a program pursuant to the Act.[7] NTIA also held meetings on November 14 and 15, 2006, to afford interested parties the opportunity to clarify comments submitted in response to the NPRM.[8]

II. Discussion

A. Eligible U.S. Households

4. After February 17, 2009, households may make one or more of several consumer choices to achieve digital-to-analog conversion, such as via cable or satellite service (where available), or through a converter device.[9] In the NPRM, NTIA proposed to define those U.S. households eligible to participate in the Coupon Program as "those households that only receive over-the-air television signals using analog-only television receivers."[10] NTIA further proposed to make households that receive cable or satellite television service, even if those households have one or more analog television signals not connected to such service, ineligible for the Coupon Program.

5. Many commenters disagreed with NTIA's proposed definition and argued that all consumer households should be eligible to receive coupons.[11] Given the

[1] *See* Title III of the Deficit Reduction Act of 2005, Pub. L. 109-171, 120 Stat. 4, 21 (Feb. 8, 2006) (the Act). Section 3002(a) of the Act amends Section 309(j)(14)(A) of the Communications Act of 1934 so that analog full-power television licenses will terminate on February 17, 2009. Section 3002(b) of the Act directs the FCC to terminate analog television licenses for full-power stations by February 18, 2009.

[2] Section 3004 of the Act.

[3] *See* subsections 3005(c)(1)(A), (c)(4) of the Act.

[4] NTIA intends to enter into a contract for services to administer the Coupon Program through a separate program acquisition plan. The contractor will be responsible for establishing and managing the systems and processes through which some of the final rules may be applied. In this document, "NTIA" should be understood to be either NTIA or its contractor.

[5] Section 3005(c)(3) of the Act.

[6] Section 3005(b) of the Act.

[7] *Request for Comment and Notice of Proposed Rules to Implement and Administer a Coupon Program for Digital-to-Analog Converter Boxes,* Notice of Proposed Rulemaking, 71 FR 42,067 (July 25, 2006).

[8] Summaries of these *ex parte* meetings are posted on NTIA's website at *http://www.ntia.doc.gov*.

[9] Not all local television signals are uplinked and delivered to satellite homes today. The extent to which satellite subscribers will have digital-to-analog conversion of local signals available to them after February 17, 2009, will depend on the availability of "local-into-local" offerings from satellite providers.

[10] NTIA proposed to define a "television household" as a "household with at least one television . . . consisting of all persons who currently occupy a house, apartment, mobile home, group of rooms, or single room that is occupied as separate living quarters and has a separate U.S. postal address." *See* NPRM, 71 FR at 42,068.

[11] *See* Association for Maximum Service Television, Consumer Electronics Association, and National Association of Broadcasters (Joint Industry) Comments at 5-11; Thomson Comments at 2; Archway Marketing Service Comments at 2; LG Electronics Comments at 5; Community

Continued

funding level and the possibility that many households with cable or satellite service may wish to purchase a converter box, commenters expressed concern about excluding any household.[12] Commenters also expressed concern about those consumers that may need to rely on over-the-air capabilities in times of emergency. Some commenters argued that the Act and the legislative history do not support NTIA's proposed definition and that the Agency lacks the statutory authority to limit the eligibility requirements.[13] For example, in Joint Industry Comments, the commenters argued that the Act and the legislative history, as well as practical considerations, ''preclude any implementation of the program that would exclude from coupon eligibility analog sets in cable or satellite-served homes not connected to those services.''[14] Likewise the Consumer Electronics Retailer Coalition (CERC) argued that there is no basis in the Act or the legislative history to support the standard proposed in the NPRM.[15]

6. Several comments raised other points in favor of expanding eligibility beyond that proposed in the NPRM. For example, some commenters noted that even cable and satellite households may need the ability to receive signals over the air in times of emergency or severe weather.[16] Others noted that limiting coupons to over-the-air-only households could disadvantage satellite customers who receive their local broadcast signals over the air.[17] Operators of Class A and LPTV stations noted that these facilities will continue to broadcast in analog after February 17, 2009, that most of these facilities are not eligible for cable or satellite must carry and that NTIA should not deny converter-box subsidies to households that rely on analog receivers to watch Class A and LPTV stations over the air, even if they have another means to view digital full-power stations.[18] Consumers Union contended that denying converter boxes to all households would cause disruptions in service that could undermine consumer support for the digital television transition.[19] RadioShack suggested that limiting eligibility could reduce demand for converter boxes, thus raising their costs and potentially harming low-income households.[20]

7. NTIA recognizes that limiting eligibility as proposed in the NPRM would be difficult to enforce. There are no lists of households that only receive over-the-air television broadcasts. Moreover, as the Government Accountability Office (GAO) recognized, it would be a highly challenging task to obtain a list of cable and satellite subscribers in order to identify over-the-air-reliant homes by the process of elimination.[21] In fact, it would be difficult for NTIA to determine which U.S. households currently have, or plan to obtain, an analog television set requiring a CECB. Moreover, efforts to confirm eligibility would likely delay reasonable and timely distribution of coupons.[22] Unless NTIA devoted substantial resources to review applicants'certifications of eligibility, there would be potential for waste, fraud and abuse.[23] Such efforts could also substantially increase the costs of administering the program.[24]

8. Upon careful consideration of all arguments raised in the comments for and against limiting household eligibility criteria, NTIA has decided *not* to initially limit household eligibility in the Coupon Program to households reliant exclusively on over-the-air broadcasts for television service. Accordingly, the Final Rule permits coupons to be distributed initially to all U.S. households. As proposed in the NPRM and consistent with the definition used by the U.S. Census Bureau, a ''household'' consists of all persons who currently occupy a house, apartment, mobile home, group of rooms, or single room that is occupied as a separate U.S. postal address.[25] NTIA received a comment from SunBelt Multimedia Company that requested the household definition to be expanded to allow multiple families residing at a single address to each count as a household, based on the community or income criteria.[26] NTIA recognizes that multiple families may exist in households as defined by this Final Rule, however, it would be administratively difficult to determine the number and location of these households and to establish a definition based on community or income criteria.

9. Recognizing that funds allocated for this program are limited and the possibility that over-the-air reliant television households may lose television service as a result of this decision, NTIA will permit open eligibility on a first-come, first-served basis while the Initial Funds are available (*i.e.,* until coupons valuing $890,000,000 have been redeemed and issued but not expired, in accordance with Section 3005(c)(2)(B) of the Act).[27] The Act permits funding of the program to increase by $510,000,000 to a total of $1,500,000,000 upon certification to Congress that the initial allocated amount of $990,000,000, the Initial Funds, is insufficient to fulfill coupon requests.[28] If such Contingent Funds are available for the Coupon Program, the eligibility for those coupons provided from Contingent Funds will be limited to over-the-air-only television households (Contingent Period). Consumers requesting those coupons during the Contingent Period must certify to NTIA that they do not subscribe to a cable, satellite, or other pay television service. NTIA makes this decision balancing the demand uncertainty and funding limitations with the need to prioritize contingency funds for over-the-air reliant households which will lose total access to television broadcasts after the transition date.

10. NTIA did not propose to consider ''economic need'' as part of the eligibility requirement, but solicited comment on whether it should be considered and, if so, how it should be determined. NTIA received comments opposing adoption of eligibility criteria

Broadcasters Association Comments at 3; Consumer Electronics Retailers Coalition (CERC) Comments at 5; AARP Comments at 5; MTVA Comments at 3; Joint Consumer Comments at 2-8; APTS Comments at i; RadioShack Corporation Comments at 3-6; Sodexho Comments at 4.

[12] *See* Letter to Hon. John M. R. Kneuer from Hon. John D. Dingell, Hon. Edward J. Markey, Hon. Henry A. Waxman, Hon. Frank Pallone, Jr., Hon. Bart Gordon, Hon. Eliot L. Engel, Hon. Ted Strickland, Hon. Lois Capps, Hon. Tom Allen, Hon. Rick Boucher, Hon. Sherrod Brown, Hon. Bart Stupak, Hon. Gene Green, Hon. Diana Degette, Hon. Mike Doyle, Hon. Jan Schakowsky, (Letter from Members of the House Energy and Commerce Committee) (Nov. 15, 2006) at 2.

[13] Joint Consumer Comments at 2-8; Richard Brittain Comments; Joint Industry Comments at 5.

[14] Joint Industry Comments at i.

[15] CERC Comments at 5.

[16] *See, e.g.,* Marvin Clegg Comments at 1; Richard Brittain Comments at 1; Thomson Comments at 2.

[17] *See, e.g.,* Richard Brittain Comments at 1.

[18] Community Broadcasters Association Comments at 5. Section 3002 of the Act permits Class A and LPTV facilities to broadcast in analog after February 17, 2009. Moreover, a cable system must carry a LPTV facility only if it meets certain limited requirements. 47 U.S.C. § 534(h)(2).

[19] Joint Consumer Comments at 9.

[20] RadioShack Comments at 7.

[21] *See* ''Digital Broadcast Television Transition: Several Challenges Could Arise in Administering a Subsidy Program for DTV Equipment,'' GAO-05-623T (May 26, 2005) at 11-13 (GAO Challenges Report). In addition to the cable industry's reluctance to give the government access to its subscriber lists, GAO noted that it would be difficult to merge information across the more than 1,100 cable and satellite companies in the United States. GAO Challenges Report at 12.

[22] *See, e.g.,* RadioShack Comments at 8.

[23] *See, e.g.,* Thomson Comments at 2.

[24] *See, e.g.,* Archway Marketing Services Comments at 2.

[25] *See* U. S. Census Bureau, *http://www.census.gov* (Current Population Survey — Definitions and Explanations).

[26] Sunbelt Multimedia Company Comments at 11.

[27] *See supra,* para 2.

[28] *See* Section 3005(c)(3)(ii) of the Act.

encompassing economic need because of the complications involved in such an analysis. Some commenters also asserted that NTIA lacks such statutory authority.[29] Other commenters, however, supported the idea of adopting a means test and suggested that NTIA use income or participation in other federally supported programs as a basis of determining eligibility. For example, the American Association of People with Disabilities suggested that NTIA adopt a program similar to the FCC Lifeline-Linkup phone subsidy program which uses 135 percent of the poverty level or persons who are beneficiaries of other federal assistance programs as a basis for eligibility.[30]

11. NTIA agrees that including economic need as an eligibility factor in the Coupon Program would be a complicated process. Furthermore, because this is a one-time program, it would not be cost effective to develop eligibility requirements and verification systems such as those used by other federal assistance programs, such as Food Stamps. NTIA noted in the NPRM that neither the Act nor the legislative history suggests such a requirement. Accordingly, NTIA will not consider economic need as part of an eligibility requirement for the coupon program. Moreover, the Agency will only make the Coupon Program available to individual U.S. households, as proposed in the NPRM, not businesses, schools, or other entities as suggested by one commenter.[31] The Act states that a ''household'' may obtain coupons, and there is nothing in the legislative history or the comments that suggests that Congress intended to extend eligibility beyond households.

B. Coupon Value and Use Restrictions

12. Consistent with the Act, NTIA proposed in the NPRM to issue $40 coupons to be redeemed only at certified retailers when purchasing a CECB. The Agency also proposed to place identifying serial numbers on the coupons to keep track of the number of coupons issued to and redeemed by consumers as well as to minimize fraud, such as counterfeiting. NTIA did not propose a specific form of the coupon, but requested comment on whether the Agency should issue a paper coupon or an electronic coupon card.

13. NTIA proposed to restrict each individual coupon to the purchase of one CECB. Consistent with the Act, NTIA also proposed to prevent coupon holders from using two coupons in combination toward the purchase of a single CECB. To prevent fraud, NTIA also proposed to prohibit coupon holders from returning a converter box to a retailer for a cash refund or for credit towards the purchase of another item. However, the Agency did propose to permit the even exchange for another CECB in the event of defective or malfunctioning equipment.

14. One commenter argued that a buyer should be able to use the $40 coupon to buy a converter box with deluxe features.[32] Best Buy supported only ''even'' exchanges of devices and opposed allowing consumers to return converters for a cash refund or for credit towards the purchase of an upgraded device.[33] RadioShack recommended that statements such as ''No Cash Value'' or ''Exchange Only for Eligible Converter'' be clearly printed on the coupon and in accompanying consumer material.[34]

15. Consistent with the Act, the value of the coupons issued will be $40. In no case may consumers receive any cash value for the coupon.[35] If the cost of a CECB is less than $40, retailers will only be reimbursed for the retail price of the box. Likewise, consumers cannot receive a refund or credit towards the purchase of another item if the price of the CECB is less than the $40 value of the coupon. Retailers and consumers are also prohibited from using two coupons in combination towards the purchase of a single CECB. NTIA recognizes the opportunities for fraud and abuse by permitting consumers to receive a cash refund for the value of the coupon or for credit towards another item outside of the program. Therefore, NTIA will permit an exchange only for another converter box certified under these regulations.[36]

16. Some commenters supported the use of a paper coupon. For example, one commenter stated that it was Congressional intent to issue a paper coupon with UPC coupon-type barcode, which brick-and-mortar retailers and clearinghouses could handle in the same fashion as manufacturers' cents-off coupons because this would minimize the cost of the overall program.[37] Another commenter stated that the paper coupon was both straightforward to use and provides for a fast and economical means to mail eligible applicants their coupons in a short time frame.[38] Moreover, paper coupons could have several security features, including unique serial numbers, barcodes, security paper and consumer identification.[39] Many of the comments, however, addressed the problems associated with paper coupons including the potential for fraud, delay in retailer reimbursement and increased administrative costs.[40]

17. Other commenters, particularly retailers, supported the use of an ''electronic coupon card'' (ECC) on which the $40 value can be credited towards the purchase of a CECB. Many commenters agreed that use of the ECC was the most efficient way to administer the program as well as the best way to reduce fraud.[41] CERC stated that an ECC should (a) bear a ''use by'' date on its surface and should be coded to expire after the time indicated on its surface; (b) carry a unique serialized number (encoded in a magnetic strip and printed in human-readable form on the card) that can be transmitted to a central database immediately upon submission for on-line verification; and (c) provide clear and succinct rules concerning coupon use.[42] CERC also noted that the use of ECCs would permit more consumer friendly converter exchanges.[43] It was also noted that the use of ECCs would facilitate real-time transmission of information on redemption rates which is important because transmission delays may limit NTIA's ability to monitor performance or to request additional congressional

[29] *See* Carolyn McMahon Comments; Stored Value Systems, Inc. Comments at 4; Consumer Union, Consumer Federation of America, and Free Press Comments at 9-10; Sodexho Comments at 5; Letter from Members of the House Energy and Commerce Committee at 2.

[30] *See* American Association of People with Disabilities Comments at 8 (the federal programs cited by AAPD include Medicaid, Food Stamps, Supplemental Security Income, Federal Public Housing Assistance, Low-Income Home Energy Assistance Program, Temporary Assistance to Needy Families, The National School Lunch Program's Free Lunch Program, Bureau of Indian Affairs General Assistance, Tribally Administered Temporary Assistance for Needy Families, Head Start, Tribal National Lunch Program).

[31] *See* Jon Kaps Comments (arguing that schools should be eligible to participate in the Coupon Program).

[32] Robert Diaz Comments.

[33] Best Buy Comments at 4.

[34] RadioShack Comments at 13.

[35] To further prevent fraud, the Final Rule states that consumers may not sell, duplicate or tamper with the coupon.

[36] However, if a consumer returns a CECB to a retailer, the retailer may refund to the consumer that portion of the purchase price not covered by the coupon.

[37] *See* Richard Brittain Comments.

[38] *See* Poorman-Douglas & Hilsoft Notifications Comments.

[39] *Id.*

[40] *See* CERC Comments at 7-8; Archway Marketing Services at 5-6.

[41] *See* Joint Industry Commenters at 22; CERC Comments at 7-8; Samsung Electronics Comments at 2; Joint Consumer Comments at 17; Best Buy Comments at 2; RadioShack Corporation Comments at 10.

[42] CERC Comments at 6-9.

[43] *Id.* at 8.

funding.[44] There were, however, concerns expressed about the use of ECCs. For example, ORC Macro noted that these cards may not be compatible with electronic scanning devices used by participating retailers, and that the requirement for electronic systems may eliminate small retailers from participating.[45] NTIA also received conflicting comments on whether ECCs could be encoded to limit use to a specific product.[46] Retailers suggested that ECCs may require significant up-front costs for software, payment processing and employee training.[47]

18. The coupons will not carry any ''stored value,'' but the appropriate amount will be identified on the cards and authorized for redemption when matched to the central database to verify each transaction. In light of the comments received, particularly those from retailers, NTIA will provide coupons that are capable of electronically encoding information that is necessary for the program to run efficiently and permit electronic tracking of transactions. NTIA also believes that electronically encoded coupons will reduce opportunities for fraud in the program. NTIA notes that electronic information may be encoded on paper coupons as well as plastic cards.[48]

C. Application Process

19. NTIA proposed to require coupon applicants to submit the following information: (1) name; (2) address (no Post Office Box); (3) the number of coupons required, not to exceed two coupons; (4) a certification that they only receive over-the-air television signals using an analog-only (NTSC) television receiver; and (5) a certification that no other member of the household has or will apply for a coupon. Furthermore, consistent with the Act, NTIA proposed to commence the application period on January 1, 2008 and conclude on March 31, 2009. If an applicant does not specify the number of coupons needed, NTIA proposed sending the applicant one coupon. Also consistent with the Act, NTIA proposed sending the requested coupon(s) via the United States Postal Service.

[44] Joint Consumer Comments at 17.

[45] ORC Macro Comments at 3.

[46] Archway Marketing Services Comments at 6; Sodexho Comments at 9; Best Buy Comments at 2: CERC Comments at 7; Stored Value Systems, Inc. Comments at 8.

[47] Best Buy Comments at 2; CERC Comments at 6.

[48] An example of a paper card with electronic tracking capability would be a MetroCard, used in the Washington D.C.-area Metro system.

20. Few of the comments raised concerns about the information NTIA proposed to require consumers to provide as part of the application process. CERC, however, argued that certifications that a household receives only over-the-air television signals and that no one else in the household will apply is neither consistent with the Act, nor practical nor fair.[49] Council Tree Communications Inc. argued that NTIA should allow for ''alternative methods of delivering the coupons to Indian Reservations and Alaskan Native Villages.''[50] Some commenters encouraged the Agency to make applications available in foreign languages.[51] With respect to the application period, one commenter suggested that the time period be extended to December 31, 2009, because consumers may not understand the need for a converter box until their televisions go dark after February 17, 2009.[52]

21. The Final Rule requires applicants to provide NTIA with only the information necessary for NTIA to fulfill a coupon request. Accordingly, applicants for coupons must provide the following: (1) name; (2) address; (3) the number of coupons that they require; and (4) a certification as to whether they receive cable, satellite, or other pay televison service. NTIA is sensitive to privacy concerns and is not requesting unnecessary personal identification information, such as social security numbers. Multifamily residences (i.e., a residence occupied by more than one family unit) will not be eligible for more than two coupons unless each household is occupied as separate living quarters and has a separate U.S. postal address. Coupons will be mailed via the U.S. postal service along with the terms and conditions of use. Given the sensitivity of commenters to the prevalence of Post Office Boxes in rural America, NTIA will make allowances for households on Indian Reservations, Alaskan Native Villages and other rural areas where Post Office Boxes are the only means of mail delivery. Residents of Indian reservation, Alaskan Native Villages and other rural areas without home postal delivery may be requested to supply additional information to identify the physical location of the household. With respect to the application period, NTIA will adhere to the period provided in the legislation; thus NTIA will accept applications only between January 1, 2008 and March 31, 2009.[53]

[49] CERC Comments at 9.

[50] Council Tree Communications Inc. Comments at 1.

[51] Sunbelt Multimedia Co. Comments at 12.

[52] Robert Diaz Comments.

22. Commenters agreed with NTIA's proposal to make application forms widely available.[54] NTIA will administer the program to make it accessible particularly to those in need of coupons. As part of the consumer education program, consumers will be made aware of the various ways to access and submit applications for the Coupon Program. NTIA will ensure that applications and accompanying materials are available in other languages consistent with its obligations under Executive Order 13166, ''Improving Access to Services for Persons with Limited English Proficiency,'' (Aug. 11, 2000).[55] The Final Rule provides that coupons may be requested by mail, by phone and electronically (*e.g.,* by email or through a website).

D. Coupon Expiration

23. According to the Act, coupons issued under this program are to expire three months after issuance. Accordingly, NTIA proposed to print an expiration date on each coupon and proposed that the expiration date be three months after the coupon's issuance date. NTIA defined issuance date as the date upon which the coupon is placed in the U. S. mail.

24. Although commenters agreed with NTIA's proposal to print an expiration date on the coupon, many thought that the proposed expiration date of three months after the coupon's issuance should be extended. The time that commenters suggested the date be extended varied from three to ten days after issuance to take into consideration such matters as the rural location of the consumers, homebound or disabled consumers, slow mail delivery and coupons lost in the mail.[56]

25. As stated above, the Act requires NTIA to issue coupons that expire three months after issuance. NTIA believes that three months is reasonable and allows ample time for consumers to receive and use the coupons. The expiration date will encourage

[53] Section 3005(c)(1)(A) of the Act.

[54] AARP Comments at 9-10.

[55] The Department of Commerce Limited English Proficiency guidelines are provided on the Department's website at *http://www.osec.doc.gov/ocr/doclepplan2003.pdf.*

[56] Susan Stanke Comments; Richard Brittain Comments; AARP Comments at 10; Best Buy Comments at 3; RadioShack Comments at 9; Sunbelt Multimedia Co. Comments at 11. *See also* Ralph L. Mlaska Comments (coupons issued in first 6 months of the year should expire in December; coupons issued in the last 6 months should expire in July of the following year); George McLam Comments (program should last all of 2009).

consumers to use coupons promptly and will permit NTIA to use funds from expired coupons to issue coupons to other households. Accordingly, NTIA adopts a rule that coupons will be issued with an expiration date of three months after the issuance date. Three months will further be defined as 90 calendar days to provide a uniform redemption period for all coupon recipients. The issuance date will be the date the coupon is placed in the U. S. Mail.

E. Coupon-Eligible Converter Box

26. The Act defines the term ''digital-to-analog converter box'' (a CECB) as ''a stand-alone device that does not contain features or functions except those necessary to enable a consumer to convert any channel broadcast in the digital television service into a format that the consumer can display on television receivers designed to receive and display signals only in the analog television service, but may also include a remote control device.''[57] NTIA's Final Rule adopts technical specifications and features required for a CECB to qualify for the Coupon Program. Manufacturers are free to market converter boxes which do not comply with the requirements of the Final Rule, although such devices would not be eligible for the Coupon Program.

27. NTIA acknowledges that many sections of the NPRM incorporate standards or rules adopted by the FCC regarding digital television transmission or receiver requirements, and also incorporate industry standards and guidelines adopted by the Advanced Television Systems Committee (ATSC), CEA or other organizations.[58] NTIA's incorporation of these industry standards and guidelines or FCC standards and rules into its regulations is intended to assist converter-box manufacturers by gathering NTIA's basic converter-box requirements in a single place. NTIA's regulations do not supercede the FCC's authority, affect any FCC requirement or revise any of the industry standards and guidelines discussed in this document. In these regulations, NTIA adopts technical specifications and features required for a CECB. NTIA recognizes that CECBs are not currently available to consumers, and that manufacturers will have barely 12 months to bring converter boxes compliant with NTIA specifications to market, less than the typical 18–month manufacturing cycle.[59]

28. NTIA underscores that the converter boxes that will be eligible for this program are in development and are not yet commercially available. NTIA cannot warrant the performance, suitability or usefulness of any CECB.

29. The NPRM requested comment on NTIA's proposed rule to define the converter box eligible for the Coupon Program. The NPRM presented several guidelines which NTIA used in developing the proposed rule and analyzing the comments submitted by the public. These guidelines include the ability of consumers to continue receiving broadcast programming in the same receiving configuration (*e.g.,* same household antenna, same location) as used for the existing analog reception; that the CECBs be inexpensive but meet a minimum performance level; and that they should be easy to install and operate.[60]

30. The NPRM requested comment on several related issues, including the appropriate minimum technical capabilities for CECBs, their features; and the extent to which NTIA should consider certain standards, such as energy efficiency, in determining the type of converter box that would be eligible for the Coupon Program. Comment was also sought on how NTIA can determine whether a converter box meets the requirements of the Coupon Program and how the CECBs should be identified so the public is informed that a specific box is eligible for a coupon. Comments were received on each of these issues as well as additional areas. Each of these is discussed in the following sections.

a. Minimum Technical Specifications: ATSC Guidelines A/74 and FCC Part 73

31. The NPRM stated that ''[f]or purposes of the coupon program, NTIA proposed certain standards for a minimum-capabilities converter box that simply converts an ATSC terrestrial digital broadcasting signal to the analog National Television Standards Committee (NTSC) format.''[61] The NPRM proposed that the converter box should be capable of receiving, decoding and presenting video and audio from digital television transmissions as specified in FCC Part 73 (47 CFR Part 73) and that meet the ATSC Recommended Practice: Receiver Performance Guidelines ATSC A/74 (A/74).

32. NTIA received many comments regarding the technical specifications proposed in the NPRM. All the comments agreed that A/74 should form the basis of the technical specifications for the CECB.[62] One commenter, Zoran, urged NTIA to adopt, but not exceed, the A/74 guideline. Zoran stated that ''[e]xceeding A/74 on a basic set top box calls for over engineering and the use of non-commodity parts that increase cost exponentially.''[63] Many of the commenters recommended that NTIA adopt performance specifications for the converter box that go beyond the receiver guidelines contained in A/74. The Joint Industry Comments noted that there have been ongoing improvements in technology since the A/74 guidelines were adopted in 2004 that would enable NTIA to set reasonable requirements exceeding A/74 performance levels in some areas and also to fill in some requirements for performance levels where A/74 only specified test procedures.[64] MTVA, an association of television stations that serve the New York City metropolitan area, echoed the Joint Industry Comments and indicated that it may be possible to improve on the A/74 performance levels with the fifth generation of VSB decoder chips and new RF tuners that have been developed since A/74 was adopted.[65] Charles Rhodes, former Chief Scientist of the Advanced Television Test Center, that tested the DTV systems adopted by the FCC in 1996, stated that A/74 was just a guideline and was never intended to serve as a minimum performance standard.[66]

33. The New America Foundation *et al* (NAF) also recommended that NTIA establish performance specifications beyond those contained in A/74.[67] NAF's concerns regarding NTIA converter-box specifications extend beyond the delivery of digital television to those who currently depend on analog television. NAF argued that the quality of the converter boxes NTIA mandates will affect the utility of the white spaces within TV channels 2–51

[57] *See* Section 3005(d) of the Act.

[58] FCC receiver standards are set forth at 47 CFR 15.117; FCC transmission standards are set forth at 47 CFR 73.682. Examples of industry standards and guidelines incorporated in this Final Rule are ATSC A/74 and CEA 909.

[59] Thomson Comments at 8.

[60] NPRM, 71 FR at 42,069-70.

[61] *Id.* at 42,069.

[62] *See* e.g., Funai Comments at 7; Microtune Comments at 1; Motorola Comments at 2.

[63] Zoran Comments at. 2.

[64] Joint Industry Comments at i. *See also* LG Electronics Comments at 10; Samsung Comments at 2; Thomson Comments at 4.

[65] MTVA Comments at 9-10.

[66] Charles W. Rhodes Comments at 1.

[67] *See* Comments from New America Foundation, Media Access Project Consumer Federation of America, Wireless Internet Service Providers Association (Wispa), Acorn Active Media Foundation Community Technology Centers' Network, Champaign Urbana Community Wireless Network (Cuwin), The Ethos Group, and Freenetworks.org (collectively, referred to hereafter as NAF Comments).

and noted that, in an FCC NPRM on ''Unlicensed Operation in the Broadcast Bands'' (Docket 04–186), the FCC expressed concern that low-quality DTV receivers could severely impact the utility of the white spaces within TV channels 2–51.''[68] NAF suggested that desensitization performance of the converter boxes should be considered and should be equivalent to most of the stand-alone TV sets presently marketed. NAF also proposed that detailed engineering measurements be made of the susceptibility of current DTV receiver designs to interference from out of band signals.[69] NAF noted that the FCC was conducting tests that will not be available until mid–2007, but presented preliminary results of the three receiver tests it funded at the University of Kansas.[70] Raising another issue regarding interference, MTVA recommended that NTIA adopt MTVA specifications for NTSC into DTV taboo channels (television channels that cannot be used because of interference with other channels).[71] MTVA did not provide laboratory or real world measurements supporting its recommendation or information on whether manufacturers can currently build DTV equipment capable of meeting proposed specifications.

34. The comments filed by these organizations all highlight areas where the commenters believe the A/74 Receiver Performance Guidelines of June 18, 2004, do not provide a sufficient level of performance for the CECB. The technical comments and thoughtful recommendations of these commenters prompted NTIA to reexamine the NPRM proposal that the A/74 guidelines be adopted as the performance specifications for the CECBs.

35. While all of these commenters recommend that NTIA adopt specifications or tests to qualify a CECB that go beyond those in the A/74 guidelines, they each present differing technical recommendations.[72] NTIA shares the concern of the commenters that CECBs perform at a level to meet the reception needs of the American public. NTIA has carefully analyzed the recommendations presented by the commenters, and has seen no scientific data that any proposed set of technical specifications will ensure any given level of performance of converter boxes in real-world environments. Many of the commenters recommend that further tests be performed.[73] Given the requirements of the Act that coupons be available for CECBs early in 2008, there is time neither for additional analysis testing as proposed by the commenters nor for the establishment of industry-accepted standards following such tests.[74]

36. While NTIA cannot guarantee the performance of the CECBs, NTIA intends that coupons be used for converter boxes using current technology available in the marketplace. To this end, NTIA recognizes that digital reception technology has advanced in the two years since the adoption of A/74. Further, NTIA recognizes that in order to qualify a converter box to meet minimum specifications, it must, in the words of the Joint Industry Comments ''fill in some requirements for performance levels where ATSC A/74 only specified test procedures.''[75]

37. Having reviewed the comments filed by many parties, NTIA has accepted the technical recommendations of the Joint Industry Comments as the basis for the minimum technical specifications of the CECB. The Joint Industry Comments represent a collaboration by the broadcast industry and the consumer electronics industry to present a set of technical specifications which both industries believe can provide the American consumer with a high-quality, low-cost and easy-to-use CECB. The Joint Industry Comments use the A/74 guidelines as the basis for their proposal, but propose several revisions to reflect advances in technology in the two years since the A/74 standard was adopted. Further, they propose target performance levels in several areas where A/74 only specifies test procedures. The NAB and MSTV have funded the development of converter-box prototypes from two manufacturers which they state demonstrate that the technical specifications they propose are ''clearly achievable in practical products designed to be amenable to production in mass manufacturing quantities. Further, the project results provide tangible evidence that a high-quality, low-cost converter box can be built with measured performance that exceeds the levels specified in the ATSC A/74 Recommended Practice on Receiver Performance in several important areas and consequently can provide reliable reception under a variety of real-world conditions.''[76]

38. NTIA believes that CECBs should be produced according to specifications currently accepted by major manufacturers. It would be contrary to the public interest if coupons were used to purchase converters designed with obsolete or poorly performing components.[77] On the other hand, some commenters suggested technical specifications that have not been widely agreed upon nor quantified; and products in widespread commercial deployment have not been tested to these specifications. The technical specifications adopted by NTIA should provide American consumers with an economical CECB containing state-of-the-art technology available today from manufacturers within the time frame required by the Act.

39. Therefore, NTIA adopts the required minimum features and technical specifications in Technical Appendix 1 of the Final Rule. In addition, NTIA specifies permitted and prohibited features of a CECB in Technical Appendix 2.

b. Converter-Box Antenna Inputs

i. Smart Antenna

40. The NPRM proposed that the only input to the converter box shall be for an external antenna. The NPRM stated that ''[a] single input (Type F connector) ensures that only an antenna can be

[68] NAF Comments at 2; *See also* Charles W. Rhodes Comments at 1.

[69] NAF Comments at 5.

[70] NAF 2nd Comments (November 16, 2006).

[71] MTVA Comments at 17.

[72] For example, while A/74 does not require any specific number of field ensembles to be successfully demodulated, the Joint Industry Comments recommended that a converter box successfully demodulate 30 of the 50 field ensembles included in A/74. Joint Industry Comments at Appendix 4. Rhodes recommends that ''tests of ACI [adjacent channel interference] should be carried out over the full range of D [desired] signal powers that will exist within the coverage area of the transmitter,'' while A/74 only specifies three desired signal power levels. Rhodes Comments at 4. MTVA stated that multiple interfering signal tests are important but said that reasonable interference levels are not yet known. MTVA Comments at 15. NAF indicated that in addition to the A/74 guidelines, tests must also include desensitization performance. NAF Comments at 5.

[73] For example, the MTVA noted that ''reasonable interference values are not yet known at this time, but should be investigated (with lab testing) in the near future recognizing current tuner technology.'' MTVA Comments at 15. *See also* Charles Rhodes Comments at 7 (''testing should cover the same desired signal power range as in single Taboo testing above....It is my intention to actually perform these tests in my own laboratory in the next few months''); NAF Comments at 5 (''detailed engineering measurements as to the susceptibility of current DTV receiver designs to interference from out-of-band signals are needed.'').

[74] ''[A]ssuming NTIA adopts final rules by January 1, 2007, manufacturers will have barely 12 months to bring compliant converter boxes to market-less than the typical 18-month manufacturing cycle.'' Thompson Comments at 8.

[75] Joint Industry Comments at 1.

[76] *Id.* at 13.

[77] Letter from Members of the House Energy and Commerce Committee at 2 (stating that converter boxes should, at a minimum, replicate the picture and audio quality consumers experience today when watching their analog televisions).

connected to eligible boxes thus ensuring use of such boxes as for over-the-air television reception only.''[78] The F-type connector is the standard antenna input in most television receivers. While the F-type connector was supported by all who commented on antenna inputs, many commenters requested that an additional antenna input be permitted in the CECB. Most of the comments proposing an additional antenna input requested the flexibility to include an interface for a technology known as a smart antenna.[79] A smart antenna allows for automatic electronic steering and signal-level control so a consumer can receive the best signal for each channel. The Joint Industry Comments stated that in many markets, television stations' transmitters are located on different sides of the population center due to separation requirements or other practical considerations outside their control. In these instances, consumers can achieve the best reception using electronically steered smart antennas.[80]

41. MTVA stated that in difficult reception environments, the DTV video and audio is either perfect or nonexistent and the use of a smart antenna can mean the difference between having good DTV service or no service.[81] CERC noted that a smart antenna would ''better allow consumers to adjust for propagation characteristics and set capabilities. This may minimize consumer disappointment and post-sale product exchanges.''[82]

42. Zoran, however, opposed the use of a smart antenna and only supported the use of a passive antenna. RadioShack supported the option of a smart antenna interface in a CECB. In its comments, RadioShack did not propose that a smart antenna interface be mandated as it will add unnecessary cost for many consumers, but recommended that it should be an option in a certified converter box for those consumers who seek it.[83]

43. NTIA recognizes that DTV reception can be difficult in many regions of the country. The NPRM stated that ''[i]deally, a converter box should be able to receive digital broadcast signals in the same receiving configuration (*e.g.,* same household antenna, same location) as used for the existing analog reception.''[84] NTIA notes, however, recent GAO congressional testimony indicating that antenna reception of digital signals may vary based on a household's geography and other factors.[85] In addition, antennas configured for primarily VHF service may not be as effective as many stations switch to UHF frequencies.

44. After reviewing the comments from Joint Industry Comments, MTVA and others, as well as the GAO congressional testimony, NTIA concludes that many consumers may wish to use smart antennas. While NTIA expects that the industry will continue to work on improving the performance and reduce the cost of both passive and active smart antennas, NTIA believes that many consumers will benefit from smart-antenna technology to receive over-the-air digital television broadcasts. It is clear, however, that a smart-antenna interface will add to the cost of the converter box and will not be needed by many households.

45. In order to permit the inclusion of a smart antenna, but not add to the cost of the converter box for those who do not require this capability, the Final Rule will *permit*, but not require, manufacturers to include in their CECBs the circuitry and connectors associated with the so-called smart-antenna interface.

ii. Bundling

46. In its comments, Funai supported the use of a smart antenna and recommended that ''the 'bundling' of such an antenna with a DTA box should not preclude eligibility for the subsidy.''[86] Funai suggested that ''[a]lthough prices may fluctuate due to market conditions, we conservatively estimate that it is possible to price a DTA and Smart-Antenna bundle at less than $100.''[87] NTIA does not believe that the bundling of a smart antenna with a converter box meets the requirement of the Act which defines a CECB as a ''stand-alone'' device.[88] The purchase of a smart antenna at the same time a consumer purchases a converter box equipped with a smart-antenna interface will ease the installation and operation of the converter box for many people. Manufacturers or retailers may wish to offer combined purchases of converter boxes with smart antenna interfaces and smart antennas at promotional prices. The CECB, however, must be presented for sale at all outlets as a stand-alone single unit and cannot be sold conditioned on the purchase of any other items.

iii. CEA–909

47. CEA–909 is the current industry standard for a smart antenna interface. MTVA stated that ''eligibility should not be limited to only devices that comply with this standard (CEA–909) since such a requirement could preclude or delay technological advances in this area that are now being considered.''[89] NTIA recognizes that technological advances are being made in many areas of digital television broadcasting. In order for this program to proceed so converter boxes can be available to the public in 2008, however, NTIA must establish a Final Rule to specify CECBs which manufacturers will build during 2007. A reference to this standard will be included in the Final Rule for the program.

iv. 300 Ohm Inputs

48. The Community Broadcasters Association (CBA) did not object to NTIA's proposal that a CECB have an RF input, but recommended that ''manufacturers who choose to add a 300–ohm input with screw terminals should not be penalized for doing so.''[90] The CBA comments included no further explanation or information supporting this recommendation. NTIA recognizes that use of 300–ohm antenna inputs is old technology and has no information on the number of television receivers in use today that are equipped only with 300–ohm antenna inputs. NTIA also recognizes that many inexpensive indoor ''rabbit-ear'' antennas have 300–ohm connectors. NTIA notes that manufacturers of television receivers commonly include inexpensive matching transformers to connect 300–ohm ribbon leads to Type F inputs rather than including built-in 300–ohm antenna inputs, and that such transformers are commonly available where television receivers are sold. We believe that the use of these inexpensive transformers is the most economical method of meeting the needs of those consumers who have television receivers which only contain 300–ohm inputs. The Final Rule, therefore, will *permit*, but not require, manufacturers to include matching transformers to connect 300–ohm ribbon leads to the required Type F connectors. The Final Rule will also permit manufacturers to

[78] NPRM, 71 FR at 42,070.

[79] A standard for smart antenna interfaces is defined by the CEA-909 Antenna Control Interface standard, which is included in the A/74 guidelines, Section 4.2.

[80] Joint Industry Comments at 17.

[81] MTVA Comments at 5-6.

[82] Zoran Comments at 3; *but see* CERC Comments at 10.

[83] Radio ShackComments at 20.

[84] NPRM, 71 FR at 42,069.

[85] *See* GAO Challenges Report at 6.

[86] Funai Comments at 10.

[87] Funai 2nd Comments at 1-2.

[88] *See* Section 3005(d) of the Act.

[89] MTVA Comments at 5.

[90] CBA Comments at 6. Richard Brittain also noted that older sets still have 300–ohm ribbon leads and screw terminals instead of Type F connectors. *See* Richard Brittain Comments.

provide connectors for 300–ohm inputs on the CECB.

c. Analog Signal Pass Through

49. The National Translator Association recommended that the CECBs pass analog signals directly through without processing or modification.[91] The CBA also requested that NTIA require that CECBs pass through an analog signal, either actively or passively. CBA noted that Class A and LPTV stations are not subject to the February 17, 2009 end-of-transition deadline, applicable to full-power stations. It indicated that it was important that the converter box not block the analog signal.[92] LPTV licensee Island Broadcasting noted that thousands of LPTV stations in the United States will remain analog after the transition and are not carried on a cable system or other multi-channel video delivery service. Island recommended that the converter box contain a feature to pass through the analog signal from the antenna to the TV receiver, either when the box is shut off, the signal is passed, or by means of a built in by-pass switch.[93] Funai, however, noted that ''[a]n analog pass through, while conveniently retaining legacy analog TV support, would degrade the RF noise performance of all so-equipped DTA tuners by 3dB–a penalty that could not be recovered by any consumer with such a unit.'' Funai recommended that a consumer purchase a separate switch and/or external splitter to receive analog television.[94]

50. NTIA is sensitive to the needs of consumers who will wish to continue to view over-the-air analog television during and after the digital transition. Not only will many consumers continue to rely on analog television reception of Class A stations, LPTV stations and translators after the transition, many consumers who purchase the CECB will require the ability to receive analog television signals during the transition period as not all full-power television stations in the United States have completed their digital build-out. NTIA, however, is reluctant to require an analog pass through feature because it will result in a reduction in received signal level and in increased cost to all consumers who purchase a CECB. The amount of reduction in receiver sensitivity and increased cost is dependent on how the analog pass through feature is implemented. This reduction may not be noticeable to consumers who receive strong signals in urban areas, but may mean that consumers who receive marginal digital and analog signals will be unable to receive television signals via the CECB. NTIA notes that switches and external splitters are commonly available where television sets are sold. A single A/B switch will not fully bypass a CECB, however, creating a difficult wiring scenario for the consumers. Splitters and their inherent loss as well as additional cabling makes their use less than optimal in fringe reception areas. NTIA strongly urges manufacturers to take into consideration the needs of consumers to receive analog television along with digital television in the development of CECBs and to investigate minimal signal loss solutions that would ensure an acceptable analog signal pass-through. In the Final Rule, NTIA *permits* that the converter box to pass through the analog signal from the antenna to the TV receiver.

d. Converter-Box Outputs

i. RF and Composite Video Outputs

51. The NPRM proposed that the converter box contain the following outputs: Composite video and stereo audio (all three RCA connectors) and Channel 3 or 4 switchable (NTSC) RF (Type F connector) output. RadioShack recommended that NTIA permit the inclusion of an RF modulator output as an option, but not require this feature. RadioShack stated that ''there are only a limited number of households with televisions requiring RF modulators, and of those households, many have already purchased RF modulators in order to connect such devices as DVD players and game consoles, etc. Thus, mandating that *all* consumers pay extra for a product they do not need or may already have in order to satisfy the needs of a smaller number of consumers seems inconsistent with Congress' desire to subsidize a reasonably priced converter box.''[95]

52. Most commenters on the subject supported the inclusion of both composite video/audio and RF outputs in the converter box. THAT Corporation (THAT Corp.) noted in its comments that ''[t]o utilize these (composite video) outputs, consumers must be able to connect three separate cables from these converter box outputs to three corresponding inputs on the TV monitor. . . such a hookup requires a degree of technical competence lacking in many consumers.''[96] All receiver manufacturers supported the inclusion of both RF and composite outputs as did comments received from other members of the public. A few commenters suggested that NTIA permit the converter box to include an S-video output.[97] S-video is an analog output which delivers standard definition video to the television receiver.

53. As noted earlier, NTIA seeks to ensure that the CECB will be easy to install and operate. The RF output is very easy to use as it only requires the consumer to connect a single cable between the converter box and the analog television. The Final Rule, therefore, *requires* that the CECB include an RF output and also *requires* that the CECB include composite outputs for those consumers who wish to continue to use the features provided by this technology. NTIA will also *permit* a S-video output which provides a better standard definition picture using a simple and inexpensive hookup with one cable.

54. In its comments, Funai recommended that NTIA clarify the types of outputs that would not be permitted in a CECB. Funai commented that ''we feel that it is inappropriate to extend Coupon Program eligibility to devices that support high-definition (HDTV) viewing, *i.e.*, a display with higher-than-standard definition video resolution.''[98] Funai then listed a series of connectors which it felt should not be permitted in the NTIA supported converter box. Funai requested that the following connectors be excluded from the converter box program: Digital Video Interface (DVI), high-definition multimedia interface (HDMI), analog component video (YPbPr), computer video (VGA), as well as USB IEEE–1394 (sometimes trademarked as iLink or Firewire), or IEEE–802.3 (Ethernet) or IEEE–802.11 (wireless).[99] Funai further recommended that ''any device that includes an integrated display intended for use as the primary video presentation should be ineligible for the Subsidy.''[100]

55. In the NPRM, NTIA proposed that ''the converter box would not be required to render pictures and sound at more than standard definition

[91] National Translator Association Comments at 1.

[92] CBA Comments at 3.

[93] Island Broadcasting Comments at 2. Similar comments were filed by the Association of Public Television Stations (APTS), which recommended ''that NTIA allow eligible converter boxes to contain a built-in and easily workable A/B switch.'' APTS Comments at 30. Richard Brittain recommended a pass through of analog signals if the box is turned off. *See* Brittain Comments.

[94] Funai, 2nd Comments at 2 (Nov. 17, 2002).

[95] RadioShack Comments at 19.

[96] THAT Corp. Comments at 8-9.

[97] For example, Zoran, Brittain, and Diaz recommended that NTIA permit S-video as an output. *See* Zoran Comments at 1; Richard Brittain Comments; Diaz Comments at 1.

[98] Funai Comments at 11.

[99] *Id.* at 11-12.

[100] *Id.*

quality.''[101] This proposal follows from the definition of a converter box contained in the Act, which limits the converter box to a unit so ''the consumer can display on television receivers designed to receive and display signals only in the analog television service.''[102] If NTIA were to permit any digital output to the CECB, then it would cease to be a digital-to-analog converter and would become a digital tuner capable of providing a digital signal to a television monitor. This would clearly be beyond the plain language of the Act which states that the CECB shall ''convert any channel broadcast in the digital television service into a format that the consumer can display on television receivers designed to receive and display signals only in the analog television service.''[103]

56. Therefore, NTIA specifies in the Final Rule those connectors that will not be permitted in a CECB. Likewise, NTIA clarifies in the Final Rule that CECBs are *prohibited* from containing items such as display screens, recorders or storage devices that go beyond the simple task of converting a digital television signal to an analog signal for display on analog television receivers.

ii. Audio outputs

57. Two organizations, the WGBH National Center for Accessible Media (NCAM) and THAT Corp., commented on NTIA's proposal that the outputs include stereo audio. The NPRM proposed that ''[t]he outputs shall be channel 3 or 4 (NTSC modulated signals), composite video (NTSC baseband), and audio (stereo).''[104]

58. THAT Corp. requested that NTIA clarify the stereo requirement proposed in the NPRM. They noted that the proposed output with ''composite video (NTSC baseband), and audio (stereo)'' will provide the analog television receiver with a stereo audio signal. THAT Corp. continued stating that the proposed output on ''channel 3 or 4 (NTSC modulated signals)'' does not, by itself, provide a stereo signal to the analog television receiver. THAT Corp. notes that ''the RF output will contain stereo (left/right) audio information if, and *only* if, the output contains BTSC stereo audio information.''[105] They recommended that NTIA specify that the RF output must contain BTSC stereo audio information.

59. NCAM recommended that the converter boxes' audio outputs support the Secondary Audio Program (SAP) service where video description for blind individuals is provided. NCAM indicated that video description within digital television signals will be delivered via multiple ancillary audio services (including alternate language audio) and these additional audio channels should be available via the subsidized converter box.[106] NTIA notes that television stations are not required to broadcast video descriptions.[107] None of the commenters provided information regarding the number of digital television stations providing video description services, the number of people served by such services, or the number of manufacturers currently building digital television equipment capable of processing such services. NTIA believes that it would be desirable for manufacturers to include a capability in CECBs that will enable the use of SAP type services, including video description.[108] We note that because digital television encodes audio in a different manner than the encoding used in analog television, digital television does not utilize the SAP channel present in analog television. Standards and guidelines for digital television audio are contained in ATSC publications A/52, A/53 and A/54.[109] Section 6.6 of A/54 provides for two types of main audio service and six types of associated services, including associated services for the visually impaired (VI). The A/54 standard also permits the transmission of secondary language programming and reserves associated audio services for the hearing impaired (HI) and for emergencies (E). Because of the important public services that may be provided by these associated audio services, NTIA will *permit* CECBs to be capable of processing these associated audio services broadcast by a digital television station, particularly as more stations provide them in the coming years.

60. Manufacturers may provide output for the main channel audio service and associated audio services on the RF Type F connector by using either of the following two methods. NTIA will *permit* manufacturers to follow current industry practice regarding RF outputs for audio/video equipment which provides a mono RF output which is switchable between a station's main channel audio and other associated audio services. In this instance, consumers could use a button on the converter box remote control to select the RF output for a station's monaural main channel audio or toggle through a station's visually impaired (VI) or other associated audio services. NTIA will also permit manufacturers to provide BTSC Multichannel Television Sound (stereo audio) in the RF output. The BTSC stereo audio signal and included SAP carrier will provide stereo main channel or visually impaired or other associated audio service to the television receiver as selected by the consumer. Consumers will also have the option of receiving stereo audio through the converter box's left/right audio outputs (RCA connectors).

iii. Multicast Reception

61. Funai asked NTIA to clarify its interpretation of the Act which defines the converter box in part, as a device ''to enable a consumer to convert *any channel* broadcast in the digital television service.'' Funai stated that the converter box ''should provide access to all 'sub-channels' of a DTV transmission, i.e., the so-called 'major and minor' channels that may be transmitted as a 'multicast' by the broadcast operator.''[110] NTIA believes that multicast capability is an integral feature of digital television transmission and the Act clearly intends that the CECB convert all channels, including those that are multicast. NTIA notes that the Act's definition requires the converter box to ''enable a consumer to convert any channel broadcast in the digital television service into a *format*

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[101] NPRM, 71 FR at 42,069-70.

[102] *See* Section 3005(d) of the Act.

[103] *Id.*

[104] NPRM, 71 FR at 42,070.

[105] THAT Corp. at 13. ''BTSC'' derives from the Broadcast Television Systems Committee, an industry group convened in the late 1970s that, primarily, added additional audio channels to NTSC, allowing stereo (left and right) audio and a second audio program (SAP) channel to be broadcast. In 1984, the FCC developed rules and specified a pilot tone for BTSC. *See* Second Report and Order, Docket No. 21323, Rad. Reg. 2d (P&F) 1642 (1984). *See* Multichannel Television Sound Transmission and Audio Processing Requirements for the BTSC System in OET Bulletin No. 60, Revision A (Feb. 1986).

[106] Combined Comments of NCAM, American Association of People with Disabilities, and Information Technology and Accessible Interface Rehabilitation Engineering Research Center, Trace Center-University of Wisconsin-Madison Comments at 2 (hereafter NCAM Comments). The secondary audio program channel is provided under the BTSC standard and the FCC does not require nor restrict the use of the SAP channel.

[107] *See Motion Picture Ass'n of Am. v. FCC*, 309 F.3d 796 (D.C. Cir. 2002) (holding that the FCC did not have statutory authority to issue video description regulations).

[108] Congress enacted this coupon program ''[t]o help consumers who wish to continue receiving broadcast programming over the air using analog-only televisions.'' H.R. Rep. No. 109—362, at 201 (2005) (Conf. Rep.). Consistent with that guidance, NTIA encourages manufacturers to incorporate features that enhance accessibility.

[109] Audio standards for digital television are contained in ATSC A/52, Digital Audio Compression Standard, (AC-3); ATSC A/53, and ATSC Digital Television Standard; guidelines for implementation of ATSC audio are contained in ATSC A/54, Recommended Practice: Guide to the Use of the ATSC Digital Television Standard.

[110] Funai Comments at 7.

that the consumer can display on television receivers designed to receive and display signals only in the analog television service.''[111] The Act, therefore, does not permit the output to another device such as a computer which might be required to capture streams of data included on the digital television transport stream. The Final Rule will clarify that a CECB is *required* to receive, decode and display all channels, including multicast channels, broadcast by digital television station that can be displayed on an analog television receiver.

e. Requirements for Closed Captioning, Emergency Alert System (EAS) and Parental Controls (V-Chip)

62. NTIA proposed in the NPRM that CECBs comply with FCC requirements for Closed Captioned, Emergency Alert System (EAS) and the required parental controls (V-chip).[112] Several commenters noted that the FCC Rules require that television tuners decode Captioning and Parental Control (V-Chip) and, therefore, NTIA regulations are not required in this regard.[113]

63. Several commenters state that there are no FCC-imposed specific EAS requirements on television receivers at this time.[114] NTIA notes that the FCC requires that all digital television stations participate in the Emergency Alert System after December 31, 2006.[115] The Emergency Alert System is an important way that national, state and local emergency management personnel reach the public with emergency messages. It is, therefore, in the public interest that all television viewers be able to receive and display EAS messages. The Final Rule will include a requirement that, in order to be eligible to participate in the NTIA Coupon Program, a CECB must be capable of receiving, decoding and displaying EAS messages broadcast by digital television stations as required by the FCC Rules.[116]

64. NTIA believes that it is helpful to manufacturers that the Final Rule provide a comprehensive listing of features required for a CECB. With regard to Closed Captioning and Parental Controls, NTIA will require that CECBs comply with the FCC receiver requirements for Closed Captioning and Parental Controls and NTIA will not impose any requirements beyond those contained in the FCC Rules.[117]

f. Tuning Capability to All Television Channels 2–69

65. There was no opposition to the NPRM proposal that the converter box tune to all television channels, 2–69. This proposed rule reaffirmed the FCC Rules that ''TV broadcast receivers shall be capable of adequately receiving all channels allocated by the Commission to the television broadcast service.''[118] NTIA clarifies that the CECB is required to receive signals for those television channels that will be ''out of core'' (channels 52–69) once the digital transition is complete.

66. In its comments, CBA notes that it is important that the tuning capability of boxes not stop at channel 51 because Class A and LPTV stations are permitted to operate on channels 52-69 on a secondary basis even after the February 17, 2009 deadline when full power stations must broadcast within the FCC's ''core'' channels, 2–51. Moreover, operation on temporary companion digital channels will be permitted on channels 52–59, even after the end of the full-power transition; and temporary flash-cut digital operations is permitted on channels 60–69 when no other channel is available.[119]

67. NTIA did not receive comments opposing the action. The Final Rule contains the requirement that the CECB receive all television channels 2–69.

g. Remote Control

68. In the NPRM, NTIA proposed that the CECB be operable by and include a remote control. The Act specifically permits NTIA to require a remote control, and remote control units are now standard with almost all consumer video equipment such as television receivers, VCR and DVD players and recorders. There were few comments on the requirement to include a remote control. Brittain noted that there may be ''real-world reasons for requiring a remote (such as to provide the minimum ATSC functionality).''[120]

69. NCAM called NTIA's attention to the difficulty the blind and visually handicapped have in using remote controls. NCAM recommended that the CECB's remote control contain dedicated keys which provide direct access to the closed captioning function and the SAP/video description function.[121] To that extent NCAM directed NTIA's attention to Section 508 related to products purchased by the Federal government. Section 508 applies to all Federal agencies when they develop, procure, maintain or use electronic and information technology.[122] Although converter boxes may fall under the definition of electronic and information technology, NTIA is not developing, procuring, maintaining or using CECBs; therefore, Section 508 is not applicable to CECBs in NTIA's program. Nevertheless, NTIA strongly urges manufacturers to take into consideration the needs of consumers with disabilities in the development of CECBs.

70. In order to ease customer use of the remote control, the Final Rule will *require* that the remote control is supplied with batteries and uses standard technology and codes commonly used by television manufacturers as part of remote controls provided with television receivers. The standard codes for the remote control will be included in the CECB instructions so consumers can, at a minimum, program an existing remote control to turn on and off both the converter box and their existing analog television receiver. The Final Rule will also *permit* the manufacturer to provide a programmable remote control which can accept the code of the consumer's existing analog receiver and related video/audio equipment.

h. Program Information Displays (Electronic Program Guide)

71. Many commenters raised the issue of whether the inclusion of an electronic program guide would disqualify a converter from being eligible for the Coupon Program. The Joint Industry Comments stated that the requirement that broadcasters transmit program

[111] *See* Section 3005(d) of the Act (emphasis added).

[112] NPRM, 71 FR at 42,070.

[113] The FCC's Closed Captioning receiver requirements are contained in 47 CFR 15.122 and incorporate the CEA 708 standard ''Digital Television (DTV) Closed Captioning'' which was developed from the CEA 608 standard. The FCC's Parental Control (V-Chip) receiver requirements are contained in 47 CFR 15.120 and incorporate the EIA/CEA-766-A standard. ''U.S. and Canadian Region Rating Tables (RRT) and Content Advisory Descriptors for Transport of Content Advisory Information using ATSC A/65-A Program and System Information Protocol (PSIP).'' FCC requirements for Closed Captioning and Parental controls were noted by Thomson, Funai and Brittain. Thomson Comments at 3; Funai Comments at 7; Richard Brittain Comments at 5.

[114] Funai, Thomson and Richard Brittain noted that there were no FCC rules regarding EAS applicable to television receivers. Funai Comments at 7; Thomson Comments at 3; Richard Brittain Comments at 5.

[115] *In the Matter of Review of the Emergency Alert System,* First Report an Order and Further Notice of Proposed Rulemaking, FCC 05-191, November 3, 2005.

[116] 47 CFR Part 11.

[117] 47 CFR 15.120, 15.122.

[118] 47 CFR 15.177(b).

[119] CBA Comments at 6; *see also* MTVA Comments at 11; Joint Industry Comments at Appendix 1.

[120] Richard Brittain Comments at 5.

[121] NCAM Comments at 3. NCAM also suggested the inclusion of a ''talking menu'' which can read out the functions that are highlighted on an on-screen menu. *Id.*

[122] *See* 29 U.S.C. 794d.

content information is included in the FCC's adoption of the ATSC A/65 standard regarding transmission of Program System Information Protocol (PSIP), including program content details in digital television broadcast signals. They felt that this requirement ''is premised on the FCC's conviction that a mechanism for locating digital channel and program content, including multicast channels, is an integral feature of the digital television experience.''[123]

72. The inclusion of an electronic program guide was supported by television receiver manufacturers Samsung, Thomson and LG Electronics. LG Electronics noted that ''[e]ase of use is particularly important given the ability of digital broadcasters to transmit multiple program streams (*i.e,* multicast) via their DTV signals.''[124] CERC recommended that the converter boxes contain program guides and the capability to process PSIP data because such features may be of assistance to consumers that are inexperienced in finding and tuning digital channels. They also note that the components and software for displaying PSIP data are commonly included in the manufacture of televisions.[125]

73. Gemstar-TV Guide International (''Gemstar'') requested that NTIA permit the inclusion of hardware and software that would enable a consumer to receive Gemstar's TV Guide On Screen electronic program guide or other third-party guides. Gemstar notes that distribution of television program information is required by the A/65 standard, which defines the PSIP. The PSIP also includes information about the multicast channels and contains the parental control (V-chip) information required by the FCC. Gemstar further notes that many televisions are equipped with built-in capability to receive and display Gemstar's TV Guide On Screen service. Gemstar stated that it is working with the Society of Cable Telecommunications Engineers regarding the Digital Video Standard 706 ''VBI-in-MPEG'' which will allow carriage of existing analog standard definition video VBI signals in digital broadcast transmissions.[126]

74. RadioShack sought clarification that it would be permissible to include full PSIP capability and noted that over-the air television viewers will see the number of broadcast channels increase fourfold and thus having the television appropriately display the channels is an important feature for these viewers. RadioShack also noted that because the functionality is imbedded in chips already, providing this functionality adds no cost to the box.[127]

75. After reviewing the comments received on the NPRM, NTIA *requires* that the converter box receive, decode and display information contained in the PSIP broadcast pursuant to the A/65 standard. NTIA notes that television receivers must decode the PSIP in order to display the parental controls required by the FCC. The basic capability of decoding PSIP information, therefore, is already required of all converter boxes. Moreover, with PSIP functionality incorporated in ATSC tuner chips, it would be costly and impractical to require manufacturers to build converters without such functionality.

76. Further, NTIA will *permit*, but not require, a CECB to display other electronic program information. As noted by many of the commenters, this capability will assist the consumer in navigating through the many channels that will be provided by digital broadcasters. NTIA believes the means to achieve such electronic program information should be left to the judgment of individual receiver manufacturers who will be *permitted* to make hardware and software modifications necessary to display electronic program information.

i. Software Upgrades

77. Several commenters recommended that NTIA require that a CECB be capable of receiving software updates from an over-the-air terrestrial broadcast distribution service.[128] Update Logic noted that the converter boxes are essentially small computers which contain a set of software programs, software that has bugs and needs updates. They also noted that in everything from PCs to cell phones to ATMs, routine and multiple software upgrades have been installed to fix errors, improve quality and maintain functionality. The converter box will be no different.[129]

78. CBA noted that digital television technology is likely to advance in the not-too-distant future, as equipment manufacturers seek to make the system more robust and efficient. If upgrade capability is forbidden, then the boxes that qualify for subsidies may become obsolete and may be discarded before the end of the useful life of their electronic components. In no event should the program impose a restriction that will shorten the useful life of the product.[130]

79. NCAM echoed these comments and added that over-the-air software download mechanisms are available to assure the continuing successful operation of the boxes and should be required as part of the maintenance program that should also be put in place by manufacturers of the devices. Software downloads will accommodate any potential future changes to emergency alerting, closed captioning or V-chip parental control ratings as they may develop.[131] Both the NAF and the National Council of Women's Organizations reiterated that converter boxes should have the capability of receiving software downloads to repair problems and make necessary updates.[132]

80. National Datacast indicated that an industry standard for software downloads exists. ''The broadcast and CD industry anticipated the need for firmware updates and created the ATSC 'Software Data Download Specification' (A–97) which was ratified in 2004.''[133]

81. After reviewing these comments, NTIA believes that the automatic software download and upgrade capability proposed by the commenters is a desirable feature that could materially ease the consumer's use of the CECB. The use of automatic software upgrades could benefit both manufacturers in updating software and the users in upgrading a CECB's authorized features. It is NTIA's understanding that this automatic software update feature was only recently field tested and is not currently commercially available, even in expensive television receivers[134] NTIA is reluctant to require that manufacturers include in a CECB this new technology which is just emerging from field tests. The Final Rule will, therefore, *permit* a CECB to receive and decode software pursuant to ATSC Standard A–97.

j. Energy Specifications

82. In response to its request for comments on whether and to what extent NTIA should consider energy usage in determining eligibility

[123] Joint Industry Comments at 16-17; *see also* 47 CFR 73.682.

[124] LG Comments at 7.

[125] CERC Comments at 10.

[126] Gemstar Comments at 6-8.

[127] RadioShack Comments at 20.

[128] Letter from Members of the House Energy and Commerce Committee at 2 (CECBs should have the capability to be updated, modified, or repaired in circumstances where problems arise).

[129] Update Logic Comments at 1.

[130] CBA Comments at 6-7.

[131] NCAM Comments at 4-5.

[132] NAF Comments at 7; NCWO Comments at 1.

[133] National Datacast Comments at 1.

[134] Field tests were completed of the ''UpdateTV'' technology in July 2006 and the service is expected to be commercially available in 2007. Update Logic Comments at 5.

criteria,[135] several comments urged NTIA to either adopt minimum requirements or, on a permissive basis, encourage manufacturers to incorporate certain energy efficiency features. In addition to several comments generally urging NTIA to address energy usage, three areas of specific recommendations emerged from the comments: (1) an automatic power down feature and maximum power level for converters in ''sleep'' or standby mode; (2) a maximum power level in the ''on'' or operating mode; and (3) the effect of an NTIA energy specification on various state regulations and proposals.

83. The majority of comments support adoption of some type of energy usage requirement into the eligibility criteria for CECBs.[136] With respect to NTIA's proposal to consider the CECB's cost, comments advised NTIA to consider that energy costs could raise the box's overall cost. According to the American Council for an Energy-Efficient Economy (ACEEE), a converter without energy usage limits of any kind would cost ''more than two times more to operate over its estimated 5 year life than its estimated $40-$50 purchase cost.''[137] Comments assert that energy standards for CECBs would reduce the energy cost for U.S. consumers, thereby lowering the overall cost of ownership.

84. The record suggests that significant operating cost and energy savings could be achieved by requiring CECBs to include an auto power-down feature and standby power limits. The Environmental Protection Agency (EPA) estimated that televisions are not in use in typical households for 18–20 hours per day, yet converter boxes may remain on during that time if no one turns them off or if there is no automatic power-down feature.[138] The EPA urged NTIA to require an auto power-down feature, to mandate that products be shipped with the feature enabled, and also suggested an auto power down feature after four hours of user inactivity, combined with a one watt power limit in standby mode.

85. A supplementary comment was received from the Joint Industry Comments with the additional support of the Natural Resources Defense Council (NRDC) and the CERC[139] requesting NTIA adopt two energy use performance specifications: (a) converters shall use no more than two watts of electricity in a ''Sleep'' state, and (b) converters shall meet an automatic power-down requirement after four hours of inactivity.[140] The Joint Industry Energy Comment also recommended these settings be enabled at the factory as default settings that could be changed by the consumer.[141]

86. Walmart also supported an automatic standby mode after four hours with a maximum allowable standby level of two watts.[142] The standby energy level of two watts is also consistent with the CEA's voluntary standard CEA–2013 and is appropriate for the narrow purposes of the converter coupon program.[143] No comments opposed adoption of a four-hour standby trigger or a two watt standby energy level. NTIA believes that consumers will benefit significantly from an automatic power-down feature triggered after four hours of inactivity and a ''sleep'' state operating power level of two watts. Therefore, NTIA will *require* these performance capabilities for eligible converters.

87. ACEEE calculated that significant cost savings could be realized through capping a CECB's operating power limits at eight watts, a reduction from an estimated 17 or 18 watts.[144] No other comments suggested an operating limit be imposed. Walmart stated that while it is ''very supportive of efforts to reduce the 'On-mode' power use due to the additional energy savings they can provide, we are deferring such discussions to other policy forums such as ENERGY STAR and state standard setting procedures.''[145]

88. We are aware that, on January 31, 2007, the EPA's ENERGY STAR program adopted voluntary specifications for converter boxes. The EPA's voluntary specifications include one watt power consumption during the ''sleep'' mode and also include eight watt power consumption during the ''on'' mode.[146] NTIA's requirements for a CECB include two watt power consumption during the ''sleep'' mode, and does not include a specification for power consumption during the ''on'' mode. NTIA urges manufacturers participating in the Coupon Program to adopt those ENERGY STAR specifications.

89. Some comments assert that cost savings could be achieved by adopting a single, national pre-emptive energy consumption standard.[147] These parties are concerned that by permitting states to enact their own energy efficiency standards for converter boxes, the cost would rise for all converter boxes as manufacturers attempt to design, manufacturer, test and distribute boxes that comply with varying requirements of individual states. Motorola generally opposed including energy standards into the regulations, but said that to the extent that an energy requirement is considered, it should be instituted at the Federal level and not the state level to avoid inconsistent and costly requirements.[148]

90. NTIA is adopting these performance capabilities solely for the purpose of implementing the Coupon Program and does not intend to influence any other Federal or state agency activity regarding energy efficiency guidelines or requirements for CECBs. Converter boxes are not yet commercially available and manufacturers are willing to design and produce them as new products with these energy efficiency requirements.[149] NTIA is also persuaded by those comments regarding the cost savings that can be achieved by converter boxes that incorporate energy efficient standards.

k. Other proposals regarding the converter box specifications.

91. KTech, a manufacturer of DTV equipment, provided several recommendations regarding features of the CECB. KTech recommended that the CECB contain a LED power light to allow users to determine if the external power is connected to the unit. KTech noted that ''a 'power-good' display function [should be] allowed on the converter as a possible health and status display of the unit.''[150] NTIA has determined that a power light LED will be useful to consumers in the operation of the CECB, and the Final Rule will

[135] NPRM, 71 FR at 42,070.

[136] Natural Resources Defense Council (NRDC) Comments at 4; American Council for an Energy-Efficient Economy (ACEEE) Comments at 1; Letter from Members of the House Energy and Commerce Committee at 2.

[137] ACEEE Comments at 1.

[138] EPA Comments at 2.

[139] Letter of CERC, The Association for Maximum Service Television, Inc., National Association of Broadcasters, and Natural Resources Defense Council to Honorable John M.R. Kneuer, (Joint Industry Energy Comments) (Oct. 25, 2006).

[140] This measurement is in accordance with industry standard, CEA 2013-A.

[141] Joint Industry Energy Comments at 4.

[142] Walmart Comments at 2; *see also* NRDC Comments at 4; ACEEE Comments at 1.

[143] CEA Standard 2013, Digital STB Background Power Consumption.

[144] *See* EPA Comments at 2; ACEEE Comments at 1.

[145] Walmart Comments at 2.

[146] The EPA ENERGY STAR specifications are available on the Internet at *http://www.energystar.gov/ ia/partners/product__specs/eligibility/dtas__elig.pdf*.

[147] Joint Industry Energy Comments at 20; LG Comments at 11; Walmart Comments at 2; CERC Comments at 11; APTS Comments at 30.

[148] Motorola Comments at 3.

[149] LG Comments at 11-12; Thomson Comments at 6.

[150] KTech Comments at 4.

require a power light indicating when the unit is turned on.

92. KTech believes that, as written, the NPRM only permits an antenna input and does not state that an external AC/DC power input connector is allowed on the CECB. In the Final Rule, NTIA clarifies the power input connections and also responds to several comments regarding the use of battery power. Brittain noted that, as a safety measure, ''many people have a second, battery-operated TV for use if the power goes out; virtually all of these are analog, and it will likely be years before similar DTVs are available at an affordable price.'' He recommended that the Final Rule ''should be written so as not to prohibit battery-powered boxes, which would be a necessity for battery-powered TVs.''[151] Because of the public interest benefit, the Final Rule, therefore, *permits*, but does not require, manufacturers to provide converter boxes that operate on battery power as well as those which use an external AC/DC power input.

93. KTech also recommends that NTIA require that the CECB display a variety of technical measurements to assist consumers in improving television reception. KTech notes a variety of possible reception impairments (*e.g.,* multi-path interference and signal blockage). KTech recommends that the CECB display test measurement results for RF power level expressed in dBm, measured Signal-to-Noise Ratio number expressed in dB, measured Bit Error Rate and other technical measurements that could aid the consumer in taking steps to improve signal reception.[152]

94. NTIA recognizes that television signal reception for some consumers will present challenges, whether analog or digital. As discussed earlier, to assist consumers in improving signal reception, the Final Rule permits the inclusion of a smart antenna interface in the signal box. NTIA notes that the A/74 guidelines states that ''[t]he capability to display received signal quality conditions on a quasi-real time basis is a feature that should be included in all digital broadcast receivers.'' To further assist consumers in improving signal reception, we include in the Final Rule provisions that *require* manufacturers to include software which will display on the television receiver signal strength and *permit* the display of other operating parameters chosen by the manufacturer. Display of signal information on the television receiver will provide information to the consumer at minimal cost. NTIA will not, however, specify exactly what such signal-quality information should contain. NTIA will follow the guideline of A/74, that ''[m]eans to achieve such signal quality indications should be left to the judgment of individual receiver manufacturers.''[153]

95. Brittain recommends that the CECB come with a Type F cable to connect the RF output of the converter box to the RF input of the television receiver.[154] Because most consumers who purchase a CECB will require at least a cable of this type, we believe that such an RF cable is integral to the use of the converter and should be required. The Final Rule will, therefore, *require* that manufacturers supply an RF cable and also *permit* manufacturers to supply additional cables, such as a cable with three RCA connectors, if they desire.

F. Manufacturer Certification

96. In the NPRM, NTIA proposed that manufacturers self-certify that their CECBs meet NTIA's performance specifications and reserved the right to test CECBs that have been self-certified to ensure that they meet NTIA's technical eligibility requirements.[155] NTIA sought comment on this proposal and other compliance testing and verification procedures that could be used for the Coupon Program.

97. Several commenting parties referred to the FCC's well-established three-tiered approach for Equipment Authorization.[156] Most supported NTIA's proposal that, after successful testing, manufacturers self-certify that their CECBs meet the NTIA eligibility features and functionality; some recommended that the manufacturer's test results be submitted to a third party for an independent level of review.[157] Most parties felt that ''certification,'' the most stringent level of FCC technical approval, applicable to new technology, computers, cell phones and other non-television products, was inapplicable to CECBs. Motorola said that a third-party certification process would decrease the amount of time available for product development and would increase the costs of bringing the device to market.[158] RadioShack opposed government testing of each model certified as it would burden manufacturers and delay product introduction.[159]

98. Most commenters supported an approval process proposed by the Joint Industry Comments, termed ''*verification plus*.'' The Joint Industry Comments stated the following:

> Rather than developing a new and untested conformity assessment program, the Joint Industry Commenters urge that NTIA leverage the existing resources of the FCC, the longstanding expert agency in this area, to conduct an efficient and accurate conformity assessment process. Specifically, NTIA should adopt a ''verification plus'' process, based on the FCC's present, well-established and well-understood verification procedures. Under these procedures, manufacturers would be responsible for conducting compliance testing at their own facilities or through an independent laboratory contracted by the manufacturer. This process would ensure efficiency and avoid delays that would occur if the FCC or any other third-party entity were required independently to test every converter box. To ensure the integrity of the program, however, the FCC, most likely through its Office of Engineering and Technology, should have the ability to be involved in the approval process before the devices are released to market. To this end, manufacturers should be required to submit their test results, along with appropriate samples of the tested equipment, to the FCC. The FCC should then review test results to ensure conformity between the converter boxes and the NTIA's performance standards which themselves are based on standards endorsed by or known to the FCC. If the FCC does not alert NTIA and the manufacturer of any problem within 15 days of when the data were submitted, the device should automatically qualify for the program. If the FCC does issue notification of a problem, however, it should expedite its own testing and rapidly notify NTIA and the manufacturer of any

[151] *See* Richard Brittain Comments.

[152] KTech Comments at 4.

[153] Advanced Television Standard Committee, Standard A/74, section 4.7 ''Consumer Interface–Received Signal Quality Indicator.''

[154] Richard Brittain Comments.

[155] NPRM, 71 FR at 42,070.

[156] ''Verification'' or self-certification; ''Declaration of Conformity'' which requires testing by third-party laboratories selected from an accredited list; and ''Certification'' under which the FCC itself tests products prior to approval. The procedures are described at *http://www.fcc.gov/oet/ea/procedures.html#sec1*.

[157] Thomson Comment at 7; LG Comments at 10; CERC Comments at 10-11; Funai Comments at 12-13.

[158] Motorola Comments at 2.

[159] RadioShack Comments at 21.

noncompliance.[160]

99. NTIA will adopt the FCC's verification process as the core of its technical acceptance plan to identify CECBs. As noted, several stakeholders in the Coupon Program, including manufacturers, retailers and broadcasters, support this proposal. This approval process will not unduly burden manufacturers and will not add significant costs or delay to the development and production of CECBs.

100. NTIA believes it is not procedurally sound for converters to become ''automatically'' eligible for the Coupon Program without agency confirmation. While manufacturers may market any converter or other device including digital-to-analog decoding functionality outside of the Coupon Program, NTIA intends to use a central electronic tracking database to track retailers' point-of-sale (POS) transactions including authorization of coupon redemptions and sales data of CECBs.[161] Action is required, therefore, by NTIA to load and update eligibility data (*e.g.,* product SKU) for each model approved by NTIA.

101. Therefore, the Final Rule requires manufacturers to conduct tests or have independent laboratories conduct tests to demonstrate that each converter model meets the features and performance specifications set forth in our regulations for CECBs. It also requires manufacturers to provide detailed certified test results along with a sample of the tested equipment to NTIA and its designee. NTIA has entered into an agreement with the FCC by which the FCC may review the manufactures' converter box test results submitted to NTIA. The FCC may test converter boxes, if necessary. NTIA will base its decision to approve each converter box upon its consultation with the FCC. A Public Notice will be published subsequent to issuance of the Final Rule to provide manufacturers with specific address and contact information regarding the required submission of these materials. NTIA will record the date test results and sample models are received and will notify the manufacturer of the date by which the agency intends to make a determination of eligibility. In general, NTIA will attempt to ensure that the review of test results and any additional testing are completed within the 15–day period proposed by the Joint Industry Comments. As promptly as possible, NTIA will issue a statement of eligibility or non-eligibility for each converter model submitted by a manufacturer. The agency will attempt to meet demand, although the pacing of manufacturer submissions may be uneven. Because it is impossible to determine at this time how many manufacturers will submit test results and equipment, whether multiple models will be built by each manufacturer, and when converters will be proposed for inclusion in the Coupon Program, NTIA must allow flexibility to establish the appropriate time frame for agency review. As noted above, NTIA will promptly include make and model number information in its POS data, consumer education materials and other files used to identify CECBs.

102. Finally, NTIA reserves the right to test CECBs. As an additional means to ensure that converters made available to the public as part of the Coupon Program meet NTIA's technical specifications, NTIA may select converters to test at any time during the course of the Coupon Program. If a converter box appears not to meet NTIA's technical specifications, NTIA will follow a process similar to that used by the FCC in consulting with the manufacturer. If a converter box model is subsequently found not to meet the features and performance specifications set forth in the Final Rule, that model will no longer be eligible for the Coupon Program.

G. Retailer Participation

103. In the NPRM, NTIA noted that participation by retailers in this program would be voluntary, and that NTIA would not compensate retailers that choose to participate. Given the nature of the program, NTIA proposed to permit consumers to redeem coupons at retailers that have established production and distribution channels and who have demonstrated that they can redeem coupons expeditiously and efficiently.[162] NTIA proposed to require retailers to adhere to and enforce coupon restrictions such as prohibiting coupon holders from using two coupons in combination towards the purchase of a single CECB and prohibiting consumers from using coupons to purchase any device other than an eligible converter box, pursuant to these regulations. NTIA proposed to reimburse retailers within 60 days after receiving sales information related to CECBs.[163]

104. Several comments were received from retail companies, organizations and members of the public addressing these proposals and raising other issues affecting retailers. NTIA believes that the regulations of this one-time program should not discourage retailer participation. Some comments noted that there has not been a government-sponsored program involving retailers quite like the Coupon Program, but that other government programs such as the USDA's Food Stamps and Women, Infants and Children's benefits may provide examples for NTIA to follow.[164]

105. Commenters made recommendations and asked NTIA for clarification with respect to (a) retailer obligations to predict or meet demand for CECBs; (b) legal liability and additional operating costs for retailers who voluntarily participate in the program; (c) the timing for retailers to be ready to redeem coupons; (d) need for confidential treatment of sales data; (e) retailer certification criteria and procedures; (f) payment terms to retailers; and (g) consumer and retailer appeals.

a. Retailer Obligations to Predict or Meet Demand

106. CERC stated that retailers and manufacturers should not be subject to sanction for an inability to predict or meet demand. They pointed out that the demand for converters may peak in the millions and then drop toward zero, all within a period as short as 90 days. At the end of the Coupon Program, excess inventory may be unsellable at any price.[165] RadioShack opposed an obligation on the part of the retailer to maintain inventory in all stores at all times because it would be burdensome and perhaps impossible to meet such a requirement.[166]

107. NTIA recognizes that the product cycle for converters is unknown and perhaps atypical of consumer electronics products generally. Furthermore, NTIA does not want retailers to decline to participate because they feel that our requirements are too burdensome or unrealistic. Therefore, NTIA will clarify that retailers are expected to follow commercially reasonable practices in ordering and managing inventories of CECBs.

108. CERC raised a related point in response to NTIA's proposal that retailers accept the obligation ''to honor all valid coupons that are tendered in

[160] Joint Industry Comments at 21-22.

[161] Letter from Members of the House Energy and Commerce Committee at 3 (coupon program should be designed so that retailers can provide updated information concerning the inventory of converter boxes in order to remedy supply difficulties promptly).

[162] NPRM, 71 FR at 42,070.

[163] *Id.*

[164] RadioShack Comments at 2-3.

[165] CERC Comments at 4.

[166] RadioShack Comments at 16.

the authorized manner.''[167] A reasonable interpretation, according to CERC, is that a retailer will honor valid coupons ''if the retailer is offering subsidized Converters for sale at the time the coupon is presented by the consumer.''[168] NTIA agrees and will not expect retailers to attempt to redeem coupons if they have no CECBs available for sale.

b. Legal Liability and Additional Cost for Retailer Participation

109. CERC described NTIA's statement in the NPRM that retailers must certify ''under penalty of law'' as ''insufficiently vague to offer guidance yet daunting in their possible consequence.''[169] CERC stated that any interested retailer would reasonably want to be fully aware of the potential for liability, to third parties as well as to the government, before agreeing to participate.[170] Similarly, RadioShack asked us to clarify what was meant that retailer certification statements would be made ''under penalty of law.'' They suggested that penalties ''would only apply to intentional efforts to defraud the program and that unintentional non-compliance or error would not be subject to penalties.''[171]

110. The Act did not include any specific government remedies or civil or criminal penalties for violations or non-compliance with the statute or the regulations promulgated by NTIA thereunder. Retailers should be aware, however, that other statutes provide for civil or criminal penalties for wrongdoing in connection with federal programs such as the Coupon Program.[172] For example, the False Claims Act establishes penalties for ''any person who knowingly presents, or causes to be presented, to an officer of employee of the United States Government . . . a false or fraudulent claim for payment or approval.''[173] NTIA clarifies that it does not intend to sanction retailers for unintentional non-compliance or error. NTIA encourages retailers and other participants in the Coupon Program to familiarize themselves with the laws that impose liability for making false statements to the Federal government, for making false claims, or engaging in other activities that violate Federal law.

111. CERC and other commenters expressed concern that they may incur substantial costs to participate in the program. CERC stated that the ''[c]onverter is a unique, limited occasion product that is likely to be subject to unique laws of supply, demand, and subsidy. As a matter of public policy, there are simply too many novel costs and risk factors, and imponderables, for NTIA to place these investments, expenses, and risks solely on the backs of retail vendors who come forward to participate in this program.''[174] The electronically trackable coupon will necessitate custom changes to retailers' point of purchase systems. RadioShack added that ''[i]n a normal retail environment, a retailer would likely consider this cost as an investment, amortized against the sales life of the many products sold in its stores. . .[But] there is nothing against which to amortize this cost - - the shelf life of the eligible converter box is as short as the 18 months of the program and the system upgrade is only required for the purchase of the few models of eligible converter boxes.''[175] Best Buy also pointed out that their ''current electronic processing systems are not able to limit an Electronic Coupon Card to a single product purchase.''[176]

112. CERC stated that it would be prudent to use some of the administrative funds authorized for the Coupon Program for ''NTIA's contract(s) with its vendor(s) to provide—in light of the apparent inadequacy of existing commercial channels—for the distribution of the necessary software and other system support to participating retailers as an included cost of the program.''[177] RadioShack said such payments could be ''considered analogous to the manufacturers' common payment to retailers of fees for the handling of their manufacturing coupons.''[178] In the NPRM, NTIA stated that it will not compensate retailers for participating in the program. NTIA maintains that it does not intend to compensate retailers directly for participation in the program. NTIA, however, fully intends to distribute and process coupons consistent with reasonable commercial practices that do not place undue burdens on participating retailers.

c. Timing of Retailers to be Ready to Redeem Coupons

113. Best Buy urged NTIA and its contractor to ''avoid the holiday months of October, November, December and January to require participating retailers to implement or upgrade any POS systems.''[179] Best Buy stated that because these months include the heaviest shopping traffic and volume of transactions of the year, it could not risk any costly down time of its systems or employees caused by complicated upgrades.[180] CERC said that ''once into the holiday shopping season, it would be very difficult for retailers to modify their point of sale and other hardware and software systems so as to be ready by January 1, 2008.''[181]

114. NTIA reiterates that it is its intent to establish regulations and procedures that are reasonable and practical in light of commercial constraints. The Act requires NTIA to accept requests for coupons between January 1, 2008 and March 31, 2009, and thus, it proposed that retailers be ready to redeem coupons starting January 1, 2008, consistent with the statutory guidance. NTIA expects widespread retailer POS system modifications to occur in the first quarter of 2008.

d. Confidential Treatment of Sales and Inventory Data

115. Consistent with the legislative history regarding measures to reduce fraud and abuse, NTIA intends to establish a system for coupon redemption that is easily audited.[182] NTIA will need to ensure that only valid coupons are redeemed by those actually requesting them, how many CECBs are being sold, how many are available in the market, and how demand is pacing for the program's initial and contingent funding. NTIA will need cooperation from retailers to provide reports of that nature. CERC pointed out that NTIA will receive ''sales data, pertaining to individual retailers and manufacturers, that ordinarily would be held confidential by these entities. Accordingly, it will be necessary to protect the non-aggregate sale data of particular retailers and their vendors, as highly confidential.''[183] RadioShack urged NTIA to clarify that its vendor ''will retain such proprietary information confidentially'' and that it

[167] *See* NPRM, 71 FR at 42,070.

[168] CERC Comments at 11.

[169] CERC Comments at 12 (*quoting* NPRM, 71 FR at 42,070).

[170] *Id.*

[171] RadioShack Comments at 16.

[172] *See e.g.,* 18 U.S.C. 1001 (''False Statement Statute''); 31 U.S.C. 3729 (False Claims Act).

[173] 31 U.S.C. 3729(a).

[174] CERC Comments at 11.

[175] RadioShack Comments at 17.

[176] Best Buy Comments at 2.

[177] CERC Comments at 11.

[178] RadioShack Comments at 17.

[179] Best Buy Comments at 2.

[180] *Id.*

[181] CERC Comments at 4.

[182] *See* Conf. Rep. at 202.

[183] *Id.* at 12.

will ''not be released to the public or to other retailers or manufacturers.''[184]

116. Again, because NTIA wishes to encourage participation by a wide range of retail entities in the Coupon Program, competitively sensitive or proprietary information provided by retailers in non-aggregated form to NTIA will be treated confidentially consistent with federal law and regulations, including Freedom of Information Act requests and court orders.

e. Retailer Certification and Procedures

117. Commenting parties generally supported NTIA's proposal that retailers comply with specific requirements by certifying that they will: (1) provide information to customers about the necessity for and the installation of a CECB; (2) have in place systems that can be easily audited as well as systems that have the ability to prevent fraud and abuse in the Coupon Program; (3) are willing to be audited at any time during the course of the Coupon Program; (4) have the ability to electronically provide NTIA with sales information related to coupons used in the purchase of CECBs, specifically tracking each serialized coupon by number with a corresponding certified converter box purchase; and (5) will only submit coupons for redemption as a result of purchases of CECB models certified by NTIA.[185]

118. CERC stated that certification should entail representations by retailers that they have ''established production and distribution channels and have demonstrated that they can redeem coupons expeditiously and efficiently.''[186] Radio Shack urged NTIA to require participating retailers ''to demonstrate that they have experience in consumer electronics retail.''[187]

119. NTIA agrees that retailers must have experience in consumer electronics retail sales sufficient to support the sale of CECBs as an additional CE product. We do not think that this program is appropriate for brand new ventures, either of the bricks and mortar type or online sellers. NTIA agrees with CERC that demonstrated capabilities as to staff, training, capacity to carry inventory and to order and take delivery of CECBs through commercial channels is important.[188] As a result, retailers will need to certify that they have been engaged in the consumer electronics business for at least one year prior to their application. This requirement may be waived by NTIA upon a showing of good cause. A determination of ''good cause'' will be based on a showing of what is the best interest of the coupon program. This application process will provide NTIA with information well in advance of the 2008 launch of which retailers will participate and what markets will be served.

120. The comments from retailers were unanimous that NTIA should dispense with the proposed consumer certifications regarding eligibility. CERC said that the two per household limit ''can be complied with by the simply electronic means of not allowing the system to allocate more than two coupons to any specific household address.''[189] RadioShack said that ''fraud would be minimized by use of an electronic coupon card'' with several suggestions on how the request, distribution, and redemption system would work.[190] NTIA agrees that an electronically trackable system will enable NTIA to reduce the chance that no more than two coupons are sent to a given household. NTIA agrees that retail employees should not be placed in the position of having to judge whether a particular customer is eligible to purchase the product. However, NTIA expects retailers to report suspicious patterns of customer behavior to NTIA. Recognizing that many scenarios may exist for fraudulent activity, NTIA will leave it to the retailer's discretion as to the type of behavior that requires notification to NTIA.

121. Some commenters addressed the need for retailers to provide information to customers about converter boxes. In support of NTIA's proposal, RadioShack said that retailers should be required to demonstrate that their sales people have received ''specific training on the necessity for and use of the converter box so that consumers can ask questions and receive accurate answers. [B]ecause the need for specific features and capabilities will vary based on the age and location of televisions, knowledgeable sales people are essential to the success of the converter box program.''[191] Best Buy said that ''[w]hile it is reasonable to expect participating retailers to inform consumers on which converter boxes are eligible for the coupon subsidy, they should not be legally required to invest in displays, placards, or advertisements. Retailers should be allowed flexibility to incorporate the list of eligible converters into existing consumer education and communications plans and materials at their own discretion.''[192] NTIA agrees and will not specify how retailers are to market or promote CECBs.

f. Payment Terms.

122. NTIA proposed that retailers participating in the Coupon Program would be required to present to the Government coupons for payment within 30 days of the redemption transaction and retain hard copies of sale information for one year, and that payment from the Government would be made to the retailer for all validly redeemed coupons within 60 days of receipt by the Government.[193] Commenting parties asserted that if an electronic system is used, there would be no need for a records retention requirement, and that the proposed 60–day payment would be unnecessarily long.

123. RadioShack said that ''a retailer may be reluctant to participate in the program, knowing that they are in effect lending the government $40 for each sale for at least 60 days.''[194] Instead, RadioShack suggested that ''reimbursement should occur immediately upon a transaction. . . [W]ith an electronic coupon card system, the reimbursement would be automatic with the transaction, saving an endless amount of time in the transaction settlement process.''[195]

124. Payments from program funds to retailers will be accomplished in a commercially reasonable manner. While it may be possible for payment to occur within a day or two if an electronically trackable system is used, payments will typically be processed no later than 3 business days after the retailer submits an authorized transaction to NTIA or its contractor. For purposes of these payments to retailers, ''business day'' means a calendar day other than a Saturday, Sunday or a federal holiday. To ensure that vendors are paid promptly, they will be required to complete a Central Contractor Registration (CCR). CCR validates the registrant information and electronically shares the secure and encrypted data with the federal agencies' finance offices to facilitate paperless payments through electronic funds transfer (EFT). To ensure payment to the retailer and provide a closed loop audit trail, NTIA will require retailers to provide positive verification that payment has been received for authorized coupon redemption transactions. With respect

[184] RadioShack Comments at 15.

[185] NPRM, 71 FR at 42,070.

[186] CERC Comments at 11.

[187] RadioShack Comments at 15.

[188] CERC Comments at 11.

[189] CERC Comments at 9.

[190] RadioShack Comments at 10-11.

[191] RadioShack Comments at 15.

[192] Best Buy Comments at 3.

[193] NPRM, 71 FR at 42,070.

[194] RadioShack Comments at 16.

[195] *Id.*

to retaining hard copies of sales information for one year, in view of the decision to allow the use of ECCs, NTIA will not require retailers to retain hard copies of this information. However, for auditing purposes, sales information must be retained for at least one year and to the extent that retailers choose to retain it electronically, they should be prepared to convert it to a hard copy format if requested by NTIA.

H. Consumer Education

125. Many commenters offered suggestions about effective means of educating consumers about the Coupon Program. While the program regulations will not directly address consumer education issues, NTIA will carefully consider the many commenters' advice as it develops a comprehensive consumer education campaign. In addition, the comments demonstrated the link between consumer education and other aspects of the proposed Rule, such as coupon eligibility, application process and certification of eligible boxes and participating retailers. Commenters offered many useful suggestions about educating consumers about the Coupon Program. Mindful of the need to manage our consumer education resources effectively and to work cooperatively with the consumer electronics and broadcast industry, community organizations, and the FCC, NTIA will build on the commenters' suggestions to develop a comprehensive consumer education effort.

III. Procedural Matters

Paperwork Reduction Act

The Paperwork Reduction Act (PRA), 44 U.S.C. Chapter 35, requires federal agencies to seek and obtain OMB approval before undertaking a collection of information directed to ten or more persons. Under the PRA, a rule creates a ''collection of information'' where ten or more persons are asked to report, provide, disclose, or record ''information'' in response to ''identical questions.''

In the NPRM, NTIA invited comment on three information collections required for the implementation of the Coupon Program. To successfully administer the Coupon Program, NTIA requested approval on three collection requirements and reporting requirements for: (1) The applications that households must submit to receive coupons; (2) the certification form for retailers that will sell the converter boxes and submit coupons for redemption; and (3) the certification form and recordkeeping and reporting requirements for manufacturers regarding converter boxes eligible for the coupon program. Specifically, comments were invited on (a) whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility; (b) the accuracy of the agency's estimate of burden including the validity of the methodology and assumptions used; (c) ways to enhance the quality, utility; and clarity of the information collected; and (d) ways to minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology.

NTIA received over 100 comments in response to the NPRM. There were no comments submitted specifically with respect to the information collection and recordkeeping requirements. The comments to the NPRM and the analysis to the NPRM, however, resulted in changes or modifications from the proposed rule to the Final Rule. Accordingly, NTIA has modified certain aspects of the information collection and reporting requirements. These modifications are discussed below.

(1) *Title:* Application for the Digital-to-Analog Converter Box Coupon

Type of Request: New Collection

Estimate of Burden: Public reporting burden for this collection of information is estimated to average .25 hours (15 minutes) per transaction

Respondents: U.S. households

Estimated Number of Respondents: 110 million

Estimated Number of Responses per Respondent: 1

Estimated Total Annual Burden on Respondents: 27,500,000 hours

This new information collection is for the application required to request and receive a coupon to purchase a digital-to-analog converter box. This collection of information is necessary for NTIA to provide the benefit to U.S. households as directed in the Act. In the NPRM, NTIA estimated the public reporting burden for this collection to average .25 hours (15 minutes) per respondent. The NPRM identified the respondents affected by this information collection as U.S. television households that receive over-the-air television in an analog format. The estimated number of respondents was 21 million U.S. television households. Because the Final Rule has been changed to include all U.S. households, the estimated number of respondents is 110 million. This estimate assumes that all U.S. households with analog television sets will apply for a coupon. The Final Rule requires consumers to submit the following: (1) name; (2) address; (3) the number of coupons requested; and (4) a certification as to whether they receive cable, satellite, or other pay televison service.

The OMB Approval Number of the information collection will be provided in a subsequent *Federal Register* notice.

(2) *Title:* Certification for Retailer to Accept and Redeem Coupons for the purchase of a Digital-to-Analog Converter Box Coupon

Type of Request: New Collection

Estimate of Burden: Public reporting burden for this collection of information is estimated to average .25 hours per respondent

Respondents: Retailers that accept coupons for digital-to-analog converter boxes

Estimated Number of Respondents: 10,000

Estimated Number of Responses per Respondent: 1

Estimated Total Annual Burden on Respondents: 2,500 hours

As part of the coupon program, retailers that choose to participate in the program by selling converter boxes must accept the coupons from consumers and then seek reimbursement from the Federal Government. The Final Rule requires retailers that wish to participate in the program to submit a form to the agency which requires them to self-certify to that they: (1) have been engaged in the consumer electronics retail business for at least one year; (2) have completed a Central Contractor Registration; (3) have in place systems that can be easily audited as well as systems that can provide adequate data to minimize fraud and abuse in retail redemption and government payment for coupons; (4) agree to have coupons box sales audited at any time during the term of participation in the coupon program by the U. S. Government or an independent auditor at no expense to the retailer; (5) will provide NTIA electronically with redemption information and payment receipts related to coupons used in the purchase of converter boxes, specifically tracking each serialized coupon by number with a corresponding converter box purchase; (6) agree only to accept coupons for, and receive payment from authorized purchases made for CECBs.

The OMB Approval Number of the information collection will be provided in a subsequent *Federal Register* notice.

(3) *Title:* Certification of Digital to Analog Converter Box

Type of Request: New Collection

Estimate of Burden: Public reporting burden for this collection is estimated at 1.25 hour per respondent

Respondents: Companies that manufacture digital to analog converter boxes who request NTIA certification

Estimated Number of Respondents: 10

Estimated Number of Responses per Respondent: 1

Estimated Total Annual Burden on Respondents: 12.5 hours

Manufacturers that wish to participate in the program must submit a notice of intent to NTIA at least three months prior to submitting test results and sample models of converter boxes. The notice shall include a brief description of the proposed converter box, including permitted as well as required features, and the date which the proposed converter box is expected to be available for testing. The notice of intent shall supply the name, title and address and phone number of an individual responsible for the manufacturer's submission. When the manufacturer submits its converter box to NTIA, it shall also provide test results along with a certification of the testing supervisor as to their authenticity, completeness, and accuracy.

The OMB Approval Number of the information collection will be provided in a subsequent *Federal Register* notice.

Executive Order 12866

This Final Rule has been determined to be economically significant for purposes of Executive Order 12866; and therefore, has been reviewed by the Office of Management and Budget (OMB). In accordance with Executive Order 12866, and Economic Analysis was completed outlining the costs and benefits of implementing this program. The complete analysis is available from NTIA upon request.

Executive Order 12988

This Final Rule has been reviewed under Executive Order 12988, Civil Justice Reform. NTIA has determined that the rule meets the applicable standards provided in section 3 of the Executive Order, to minimize litigation, eliminate ambiguity, and reduce burden.

Congressional Review Act

This rule has been determined to be major under the Congressional Review Act, 5 U.S.C. 801 *et seq*.

Regulatory Flexibility Analysis

As required by the Regulatory Flexibility Act, an Initial Regulatory Flexibility Analysis (IRFA) was prepared and published with the NPRM.[196] A copy of the IRFA was provided to the Chief Counsel for Advocacy of the Small Business Administration. Although NTIA specifically sought comment on the costs to small entities of complying with the Final Rule, no commenters provided specific cost information. NTIA has carefully considered whether to certify that the Final Rule will not have a significant impact on a substantial number of small entities. NTIA continues to believe the Final Rule's impact will not be substantial in the case of small entities. However, NTIA cannot quantify the impact the Final Rule will have on such entities. Therefore, in the interest of thoroughness, NTIA has prepared the following Final Regulatory Flexibility Analysis (RFA) with this Final Rule in accordance with the Regulatory Flexibility Act.[197]

1. Succinct Statement of the Need for, and Objectives of the Rule:

NTIA is issuing this Final Rule because of a statutory mandate to create and implement a coupon program that will affect the public under Section 3005 of the Digital Television Transition and Public Safety Act of 2005.[198] The Act requires the Federal Communications Commission (FCC) to require full-power television stations to cease analog broadcasting after February 17, 2009. After that date, households using analog-only televisions will no longer be able to receive over the air television broadcasts unless the television is connected to a converter box that converts the digital signal to analog format. As a result, the Act authorizes NTIA to create a program whereby U.S. households can apply for $40 coupons to be used towards the purchase of digital-to-analog converter boxes.

The Final Rule sets forth a framework to implement the coupon program as authorized by the Act. The Final Rule also provides clear guidance for consumers, manufacturers, and retailers regarding eligibility, responsibilities, and certifications.

2. Summary of the Significant Issues Raised by the Public Comments in Response to the IRFA; Summary of the Assessment of the Agency of Such Issues; and Statement of Any Changes Made in the Rule as a Result of Such Comments:

The only comments that directly responded to the IRFA were those submitted by Stored Value Systems, Inc. (Stored Value), although other comments submitted in response to the NPRM addressed issues raised in the IRFA.[199] Stored Value commented on the IRFA section regarding "Alternatives to Minimize Burdens." In that section, NTIA stated that the proposed self-certification by retailers for certain compliance requirements was less burdensome than other alternatives such as requiring third-party compliance, or instituting a process whereby NTIA certified compliance.[200] NTIA stated that either of those options would involve additional steps in the certification process and would therefore increase time and cost.[201] Although Stored Value agreed with our analysis, it added that "not pursuing either option would not necessarily relieve the program or associated stakeholders with conducting similar additional steps and most likely would add even increased time and cost, or possible program delay."[202] NTIA maintains that a third-party certification of retailer credentials would add costs and delay implementation of the program. The Final Rule, therefore, permits retailers to provide self-certification as to the program requirements.

3. Description and Estimate of the Number of Small Entities to Which the Rule will Apply Or an Explanation of Why no Such Estimate is Available:

The RFA requires agencies to provide a description and an estimate of the number of small entities to which the rule will apply or an explanation of why no such estimate is available.[203] Under the RFA, the term "small entity" has the same meaning as the terms "small business," "small organization" and "small governmental jurisdiction."[204] To the extent that this rule affects small businesses, the affect would be on businesses in the retail or manufacture of digital-to-analog converter boxes. The Small Business Administration defines small entities in the "radio, television and other electronic stores" sector as those organizations with less than $8 million in annual revenue.[205] With respect to equipment manufacturers, the SBA defines those small entities as those with less 750 employees.

As stated in the IRFA, NTIA does not have precise information on the number

[196] *See* NPRM, 71 FR at 42,072, Appendix A.

[197] *See* 5 U.S.C. § 604.

[198] *See* Title III of the Deficit Reduction Act of 2005, Pub. L. 109-171, 120 Stat. 4, 21 (Feb. 8, 2006).

[199] *See* Stored Value Comments at 46.

[200] *See* NPRM, 71 FR at 42,074, Appendix A.

[201] *Id.*

[202] Stored Value Comments at 46.

[203] 5 U.S.C. 604(a)(3).

[204] 5 U.S.C. 601.

[205] *See* U.S. Small Business Administration Table of Small Business Size Standards Matched to North American Industry Classifications Systems Codes, *http://www.sba.gov/size*.

of qualifying small businesses that are in the manufacturing or electronic retailing sectors that would be affected by the Final Rule. The digital-to-analog converter box is not commercially available today and the life of this particular product is limited. Thus, there is no readily available data that would assist NTIA in making an estimate as to the number of ''small business'' retailers or manufacturers that would be affected by the regulations. Moreover, none of the comments submitted in response to the NPRM addressed the number of small entities to which these regulations will apply.

According to data from the U.S. Census Bureau, there were 1014 U.S. companies in 2002 that manufactured radio and television communications equipments, and approximately 1010 of these firms were classified as small entities having fewer than 750 employees.[206] Specific figures for the number of firms that manufacture television equipment are unavailable, however, NTIA believes that some of these companies are capable of manufacturing a converter box pursuant to the standards provided in the Final Rule. In fact, several electronic equipment manufacturers submitted comments in this proceeding. There was no indication that any of these manufacturers were small businesses. To the extent that there exist small entities capable of manufacturing a converter box pursuant to the standards provided in the Final Rule, the extent to which they choose to participate in the coupon program will be a business decision and not based on any mandatory action resulting from this Final Rule. Therefore, NTIA is unable to predict with any certainty the number of small entities that will consider the coupon program an advantageous business opportunity. Moreover, the comments submitted in response to the proposed rule did not provide data that would assist NTIA in making such an estimate.

Likewise, it is not possible to ascertain the number of consumer electronic retailers that qualify as small entities for the purpose of this program. Certain data from trade associations, however, provide a glimpse of the type of small businesses that may participate in the coupon program. For example, the Professional Audio-Video Retailers Association (PARA) division of the Consumer Electronics Association (CEA) has more than 250 professional audio, video, home theater, and custom electronics specialty dealers.[207] CEA has also formed a partnership with the North America Retailers Association (NARDA), a group of independent retailers that include consumer electronics retailers that represent approximately 3,500 storefronts and accounts for over $11 billion in annual sales.[208] However, not all NARDA members may be interested in participating in the digital-to-analog converter box coupon program. In addition to consumer electronics, NARDA's members also sell and service kitchen and laundry appliances, consumer mobile electronics, computers and other home and small office products, furniture, sewing machines, vacuum cleaners, room air conditioners, and other consumer products. Moreover, NARDA's members are not limited to retailers, but also include manufacturers, suppliers and vendors. PARA and NARDA members may be specialty electronic dealers not interested in selling converter boxes. The comments submitted in response to the IRFA did not provide data that would assist NTIA in making an estimate of ''small entities.''

4. Description of Projected Reporting, Recordkeeping and Other Compliance Requirements of the Rule, Including an Estimate of the Classes of Small Entities That Will Be Subject to the Requirement and the Type of Profession Skills Necessary for Preparation of the Report or Record:

It should be noted again here that this coupon program is for a limited amount of time so there will not be any long term or recurring reporting, recordkeeping and other compliance requirements. Moreover, participation in this program is voluntary, thus any requirements would only occur if a retailer or manufacturer chooses to participate. As stated above, there is no readily available data to assist NTIA is making an estimate as to the number of ''small entities'' that will be subject to the requirements of the rule, and comments submitted in response to the proposed rule did not address such an estimate.

A. Manufacturers

The Final Rule requires manufacturers that wish to participate in the program to submit a notice of intent to NTIA at least three months prior to submitting test results and sample models of converter boxes. The notice shall include a brief description of the proposed converter box, including permitted as well as required features, and the date which the proposed converter box is expected to be available for testing. As part of this notice of intent, the manufacturer shall supply the name, title, address and phone number of an individual responsible for the manufacturer's submission. When the manufacturer submits its converter box to NTIA, it shall also provide test results along with a certification of the testing supervisor as to their authenticity, completeness, and accuracy.

Because these certification and recordkeeping requirements should be a part of a manufacturer's normal course of business, NTIA does not anticipate that a particular type of professional skill is necessary beyond that already incorporated into the manufacturer's existing business operations. It should be noted that most of the comments submitted in response to the NPRM, supported the approach adopted in the Final Rule whereby the manufacturer would conduct its own testing and submit the converter box to NTIA for ''verification plus.'' No comments submitted in this proceeding indicated that the compliance requirements of this Rule would require a particular type of professional skill.

B. Retailers

The Final Rule requires retailers to have in place systems that are capable of electronically processing coupons for redemption and payment, tracking each transaction and generating reports that are auditable. The Final Rule also requires retailers to provide transaction reports to NTIA and to retain such reports for at least one year. Retailers are required to provide NTIA redemption information and payment receipts related to coupons used in the purchase of converter boxes. To participate in the program, retailers must have engaged in electronic retailing for at least one year and must register in the Central Contractor Registration database.

Because these certification and recordkeeping requirements are typically part of a retailer's normal course of business, NTIA does not anticipate that a particular type of professional skill is necessary beyond that already incorporated into a retailer's existing business operations. No comments submitted in this proceeding indicated that the compliance requirements of this Rule would require a particular type of professional skill. The recordkeeping requirements for reports are necessary for NTIA to monitor the program to

[206] *See* U. S. Census Bureau, 2002 Economic Census, Industry Statistics by Employment Size, Radio and Television Broadcasting and Wireless Communications Equipment Manufacturing (NAICS Code 334220), Table 4, available at *http//www.census.gov/econ/census02.*

[207] *See http://www.ce.org/Membership/Divisions/98.asp.*

[208] *See http://www.narda.com.*

ensure that coupons are being utilized and redeemed. This information is necessary in the event NTIA is required to request additional program funding. Moreover, because this is a federal government program, NTIA must ensure that it can be audited as necessary.

There were comments received that the use of coupons may not be compatible with electronic scanning devices used by participating retailers and that the requirement for electronic systems may eliminate small retailers from participating. Moreover, some retailers suggested that the use of electronic coupon cards may require significant up-front costs for software, payment processing and employee training. NTIA notes again that this program is voluntary, thus any costs incurred are a result of retailers choosing to participate. With respect to limiting small retailers, NTIA did not receive comments from any small retailers that the use of electronic systems would somehow discourage them from participating. On the other hand, most of the retailers stated that incorporating electronically encoded information on the coupons was necessary for the program to run efficiently. There was no data submitted in this proceeding indicating that small retailers would not have electronic systems in place. As for those retailers that state that electronic systems would require significant up front cost, NTIA reiterates that retailers are free to set the retail price of the converter boxes. Thus, any up-front costs incurred by a retailer can be recouped.

5. Description of the Steps the Agency Has Taken to Minimize the Significant Economic Impact on Small Entities Consistent with the Stated Objectives of Applicable Statutes, Including a Statement of the Factual, Policy, and Legal Reasons for Selecting the Alternative Adopted in the Final Rule and Why Each of the Other Significant Alternatives to the Rule Considered by the Agency That Affect the Impact on Small Entities Was Rejected:

The IRFA proposed and solicited a number of alternatives to minimize the economic impact on small entities. It should be noted, as it was in the IRFA, that any significant economic impact would not be caused by the Final Rule because participation in this program is voluntary on all levels—consumers, retailers and manufacturers. Likewise, there is no significant economic impact if a small entity chooses not to participate in the program. Nonetheless the Final Rule includes steps to minimize any adverse economic impact on all participants.

a. No Limits on Pricing of the Converter Boxes

The Final Rule does not restrict the wholesale or retail price of the converter box. Thus, to the extent that manufacturers and retailers incur certain costs to provide the converter boxes, these costs may be recouped through the retail or wholesale price established by them. The alternative would have been to limit the retail price of the converter box. That alternative may cause a hardship on small entities because it would limit the ability of small entities to recoup costs involved in making the converter box available. Because this program is new and the demand for the converter box is uncertain, NTIA's decision to allow manufacturers and retailers to price the box as they deem appropriate should minimize economic burdens. Moreover, NTIA does not have the statutory authority to determine the price for the set top boxes.

b. Retaining Hard Copies of Sales Data

In the NPRM, NTIA proposed to require retailers to retain hard copies of sales information for at least one year. Retailers submitted comments asserting that if electronic systems were used, there would be no need for such a records retention requirement. Accordingly, the Final Rule dispensed with the requirement that retailers retain hard copies of sales information for one year, however, retailers are still required to retain such information electronically for one year and to convert it to a hard copy format if requested by NTIA.

c. Electronic Processing of Coupons

The comments from retailers overwhelmingly recommended the use of an electronic coupon card system. Retailers were concerned that unless an electronic system was utilized, reimbursement from the government would be delayed. As a result of these comments, NTIA intends to use retailer point of sale electronic tracking systems to authorize coupon redemptions and to track sales transactions of eligible devices. To ensure that retailers are reimbursed in a timely manner, the Final Rule permits retailers to register in Central Contractor Registration which facilitates paperless payments though electronic funds transfer. Alternatively, retailers would have to wait a longer period of time to be reimbursed by the Federal Government.

List of Subjects in 47 CFR Part 301

Antennas, Broadcasting, Cable television, Communications, Communications equipment, Electronic products, Telecommunications, Television.

■ For the reasons set forth in the preamble, NTIA adds 47 CFR Part 301, which is currently reserved, with the following:

PART 301 DIGITAL-TO-ANALOG CONVERTER BOX COUPON PROGRAM

Authority: Title III of the Deficit Reduction Act of 2005, Pub. L. No. 109–171, 120 Stat. 4, 21 (Feb. 8, 2006) (the ''Act'').

§ 301.1 Program Purposes.

Pursuant to section 3005 of the Act, (The Deficit Reduction Act of 2005), the purpose of the Digital-to-Analog Converter Box Coupon Program is to provide $40 coupons that can be applied towards the purchase price of eligible digital-to-analog converter boxes. After February 17, 2009, the Federal Communications Commission will require that all full-power television stations in the United States broadcast using digital television technology. Consumers who wish to continue to receive local broadcast television programming over-the-air using analog televisions not connected to cable or satellite service may wish to purchase digital-to-analog converter boxes in order to do so.

§ 301.2 Definitions.

Act means Title III of the Deficit Reduction Act of 2005, Pub. L. No. 109–171, 120 Stat. 4, 21 (Feb. 8, 2006).

Agency means the National Telecommunications and Information Administration of the United States Department of Commerce or its contractor.

Certified Retailer means a seller of Coupon-Eligible Converter Boxes directly to consumers that has met the requirements for certification and has been identified by NTIA as certified to redeem coupons.

Contingent Funds means those funds referenced in Section 3005 (c)(3) of the Act.

Coupon means a voucher provided by the Agency to Eligible Households which only may be used to purchase a Coupon-Eligible Converter Box from a Certified Retailer.

Coupon–Eligible Converter Box (CECB) means a stand-alone device that does not contain features or functions except those necessary to enable a consumer to convert any channel broadcast in the digital television service into a format that the consumer can display on a television receiver designed to receive and display signals only in the analog television service. CECBs may also include remote control devices. CECBs must have the features required by, and meet the technical performance specifications listed in Technical Appendix 1.

Department means the United States Department of Commerce.

Eligible Household means those Households in the United States and its territories that make a valid request for a coupon pursuant to Rule 301.3 within the time period specified by NTIA, but no later than March 31, 2009.

FCC means the Federal Communications Commission.

State includes each of the fifty states, the District of Columbia, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, American Samoa, and the Northern Mariana Islands.

Household consists of all persons who currently occupy a house, apartment, mobile home, group of rooms, or single room that is occupied as separate living quarters and has a separate U.S. Postal address. A household does not mean a Post Office Box.

§ 301.3 Household Eligibility and Application Process.

(a) To apply for and receive a coupon, an Eligible Household must:

(1) provide the name of the person submitting the request

(2) provide a United States Postal Service mailing address

(A) a Post Office Box will not be considered a valid mailing address unless (2)(B) applies

(B) residents of Indian reservations, Alaskan Native Villages and other rural areas without home postal delivery may be requested to supply additional information to identify the physical location of the household, as required.

(3) indicate the number of coupons requested, but no more than two coupons.

(b) As of January 1, 2008, requests for coupons may be submitted by mail, telephone or the Internet on forms provided by the Agency.

(c) Requests for coupons must be submitted to the Agency no later than March 31, 2009.

(d) Once Contingent Funds are available for the Coupon Program, only over-the-air households will be eligible. During the period in which Contingent Funds are available, households must certify that they do not receive cable, satellite, or other pay television service.

(e) If an applicant does not meet the above eligibility requirements, the request will be denied.

§ 301.4 Coupons.

(a) The coupon value will be $40 or the price of the CECB, whichever is less.

(b) Each Eligible Household will be limited to a total of two coupons.

(c) Two coupons may not be used in combination toward the purchase of a single CECB.

(d) Coupons will be sent to Eligible Households via the United States Postal Service.

(e) Coupons will expire 90 days after the issuance date. Issuance date means the date upon which the coupon is placed with the United States Postal Service.

(f) Consumers may not return a CECB to a retailer for a cash refund for the coupon amount or make an exchange for another item unless it is another CECB.

(g) The coupon has no cash value. It shall be illegal to sell, duplicate or tamper with the coupon.

§ 301.5 Manufacturers' Technical Approval Process.

(a) Manufacturers wishing to participate in the coupon program must submit a notice of intent to NTIA at least three months prior to submitting test results and sample models of converter boxes. Notices should be sent to DTV Converter Coupon Program, NTIA/OTIA, U.S. Department of Commerce, Room 4809, Washington, DC 20230, Fax Number 202–482–4626 and provide the name, title, address, and phone number of an individual responsible for the manufacturer's submission. The notice shall also include a brief description of the proposed converter box, including permitted as well as required features, and the date which the proposed converter box is expected to be available for testing.

(b) NTIA shall treat the notices of intent received as business confidential and proprietary information and will not release information from the notices of intent to the public unless otherwise required by law.

(c) The manufacturer will supply two production sample converter boxes to NTIA. NTIA will provide the manufacturer with mailing information in a letter of acknowledgment after NTIA receives the notice of intent.

(d) Each model proposed to be a CECB shall meet the performance specification and features set forth in Technical Appendix 1 of this Section. Each model proposed may also include ''permitted'' features set forth in Technical Appendix 2, but shall not include ''disqualifying'' features set forth therein.

(e) NTIA may issue other guidance or test-bed conditions and it is the manufacturer's responsibility to conduct tests pursuant to any guidance so provided. A manufacturer shall conduct its own tests or have a qualified independent third party conduct the tests.

(f) Reports of test conditions and test results must be clear and comprehensive so that they can be easily interpreted by NTIA and others reviewing them. The FCC may test converter boxes, if requested by NTIA.

(g) Test results shall be submitted to NTIA along with a certification of the testing supervisor as to their authenticity, completeness and accuracy based on personal knowledge.

(h) NTIA will provide prompt notice to the individual submitting test results whether the model has met technical approval and is or is not a CECB. NTIA will base its decision whether to approve each converter box upon consultation with the FCC.

(i) A list of CECBs, including make and model number, will be maintained by NTIA and regularly distributed to participating retailers for use in electronic Point-of-Sale (POS) systems.

(j) It is the responsibility of the manufacturers to resolve any performance or product defect issues with consumers and retailers.

(k) NTIA shall not warrant the performance, suitability, or usefulness of any CECB for any use.

§ 301.6 Retailer Participation.

Retailer participation is voluntary. NTIA encourages retailers to participate in the Coupon Program and to cooperate with NTIA and its contractor in the administration of an effective and efficient program resulting in high customer satisfaction with a minimum of waste, fraud and abuse.

(a) Retailer Obligations: Certified Retailers are required to redeem valid coupons toward the purchase of CECBs, and

(1) Must have systems in place that are capable of electronically processing coupons for redemption and payment, tracking each and every transaction, and generating reports that are easily auditable.

(2) Must train employees on the purpose and operation of the Coupon Program. NTIA or its contractor will provide training material.

(3) Will not be responsible for checking consumer or household eligibility but shall report to NTIA

suspicious patterns of customer behavior.

(4) Use commercially reasonable methods to order and manage inventory to meet customer demand for CECBs.

(5) Must provide transaction reports based on NTIA's requirements. Reports must be maintained by the retailer for at least one year. Business confidential and proprietary information shall not be disclosed to the public unless otherwise required by law.

(b) Retailer Certification:

(1) Retailers seeking to participate in the Coupon Program must apply for certification by contacting NTIA between June 1, 2007 and March 31, 2008.

(2) Retailers must complete the form provided by the Agency which requires the retailers to self certify that they:

(A) Have been engaged in the consumer electronics retail business for at least one year unless waived for good cause by NTIA. Good cause will be determined upon a showing by the retailer that participation would be in the best interest of the program. NTIA will issue a written determination as to whether a retailer has made a sufficient showing of good cause to waive this requirement;

(B) Have completed a Central Contractor Registration (www.ccr.gov);

(C) Have in place systems or procedures that can be easily audited as well as systems that can provide adequate data to minimize fraud and abuse in retail redemption and government payment for coupons;

(D) Agree to have coupon box sales audited at any time during the term of participation in the coupon program by the U.S. Government or an independent auditor at no expense to the retailer;

(E) Will provide NTIA electronically with redemption information and payment receipts related to coupons used in the purchase of converter boxes, specifically tracking each serialized coupon by number with a corresponding CECB purchase; and

(F) Agree only to accept coupons for, and receive payment resulting from authorized purchases made for CECBs.

(3) Retailer Certification may be revoked by NTIA if a Certified Retailer fails to comply with these regulations, with the terms of any agreement made between the Certified Retailer and NTIA, or for other actions inconsistent with the Coupon Program.

(4) NTIA will not revoke retailer certification for unintentional non-compliance or error.

(5) Retailers may contact NTIA for late application or dispute resolution for problems such as denial or revocation of certification. Such issues will be resolved on a case-by-case basis.

TECHNICAL APPENDIX 1

NTIA Coupon-Eligible Converter Box (CECB)

Required Minimum Performance Specifications and Features

REFERENCE DOCUMENTS

ATSC A/74, Receiver Performance Guidelines, June 2004

ATSC A/53E, ATSC Digital Television Standard, Revision E with Amendments No. 1 and No. 2, September 2006

ATSC A/65C, Program and System Information Protocol for Terrestrial Broadcast and Cable (Revision C) With Amendment No. 1, May 2006

Recommendation ITU-R BT.500-11, Methodology for the subjective assessment of the quality of television pictures

ATSC A/69, PSIP Implementation Guidelines for Broadcasters, June 2002

ELIGIBLE CONVERTER BOXES SHALL COMPLY WITH THE FOLLOWING MINIMUM PERFORMANCE SPECIFICATIONS AND FEATURES:

1. Decoder

Equipment shall be capable of receiving and presenting for display program material that has been encoded in any and all of the video formats contained in Table A3 of ATSC A/53E. The image presented for display need not preserve the original spatial resolution or frame rate of the transmitted video format.

2. Output Formats

Equipment shall support 4:3 center cut-out of 16:9 transmitted image, letterbox output of 16:9 letterbox transmitted image, and a full or partially zoomed output of unknown transmitted image.

3. PSIP Processing

Equipment shall process and display ATSC A/65C Program and System Information Protocol (PSIP) data to provide the user with tuned channel and program information. See ATSC A/69 for further guidance.

4. Tuning Range

Equipment shall be capable of receiving RF channels 2 through 69 inclusive.

5. RF Input

Equipment shall include a female 75 ohm F Type connector for VHF/UHF antenna input.

6. RF Output

Equipment shall include a female 75 ohm F Type connector with user-selectable channel 3 or 4 NTSC RF output.

7. Composite Output

Equipment shall include female RCA connectors for stereo left and right audio (white and red) and a female RCA connector for composite video (yellow). Output shall produce video with ITU-R BT.500-11 quality scale of Grade 4 or higher.

8. RF Dynamic Range (Sensitivity)

Equipment shall achieve a bit error rate (BER) in the transport stream of no worse than 3×10^{-6} for input RF signal levels directly to the tuner from -83 dBm to -5 dBm over the tuning range. Subjective video/audio assessment methodologies could be used to comply with the bit error rate requirement.[1]

Test conditions are for a single RF channel input with no noise or channel impairment. Refer to ATSC A/74 Section 4.1 for further guidance. (Note the upper limit specified here is different than that in A/74 4.1).

9. Phase Noise

Equipment shall achieve a bit error rate in the transport stream of no worse than 3×10^{-6} for a single channel RF input signal with phase noise of -80 dBc/Hz at 20 kHz offset. The input signal level shall be - 28 dBm. Subjective video/audio assessment methodologies described above could be used to comply with the bit error rate requirement. Refer to ATSC A/74 Section 4.3 for further guidance.

10. Co-Channel Rejection

The receiver shall not exceed the thresholds indicated in **TABLE 1** for rejection of co-channel interference at the given desired signal levels. Refer to ATSC A/74 Section 4.4.1 for further guidance.

[1] Subjective evaluation methodologies use the human visual and auditory systems as the primary measuring ''instrument.'' These methods may incorporate viewing active video and audio segments to evaluate the performance as perceived by a human observer. For subjective measurement, the use of an expert viewer is recommended. The viewer shall observe the video and listen to the audio for at least 20 seconds in order to determine Threshold of Visibility (TOV) and Threshold of Audibility (TOA). Subjective evaluation of TOV should correspond with achievement of transport stream error rate not greater than a BER of 3×10^{-6}. If there is disagreement over TOV performance evaluation, it will be resolved with a measurement of actual BER.

TABLE 1—CO-CHANNEL REJECTION THRESHOLDS.

Type of Interference	Co-Channel D/U Ratio (dB)	
	Weak Desired (−68 dBm)	Moderate Desired (−53 dBm)
DTV interference into DTV.	+15.5	+15.5
NTSC interference into DTV.	+2.5	+2.5

Notes:
NTSC split 75% color bars with pluge bars and picture to sound ratio of 7 dB should be used for video source.
ATSC high definition moving video should be used for video source.
All NTSC values are peak power; all DTV values are average power.

11. First Adjacent Channel Rejection

The receiver shall not exceed the thresholds indicated in **TABLE 2** for rejection of adjacent channel interference at the given desired signal levels. Refer to ATSC A/74 Section 4.4.2 for further guidance.

TABLE 2—ADJACENT CHANNEL REJECTION THRESHOLDS

Type of Interference	Adjacent Channel D/U Ratio (dB)		
	Weak Desired (−68 dBm)	Moderate Desired (−53 dBm)	Strong Desired (−28 dBm)
Lower DTV interference into DTV.	≥−33	−33	−20
Upper DTV interference into DTV.	≥−33	−33	−20
Lower NTSC interference into DTV.	≥−40	−35	−26
Upper NTSC interference into DTV.	≥−40	−35	−26

Notes:
NTSC split 75% color bars with pluge bars and picture to sound ratio of 7 dB should be used for video source.
ATSC high definition moving video should be used for video source.
All NTSC values are peak power; all DTV values are average power.

12. Taboo Channel Rejection

The receiver shall not exceed the thresholds indicated in **TABLE 3** for rejection of taboo channel interference at the given DTV desired and undesired signal levels. Refer to ATSC A/74 Section 4.4.3 for further guidance.

TABLE 3—TABOO CHANNEL REJECTION THRESHOLDS FOR DTV INTERFERENCE INTO DTV

Channel	Taboo Channel D/U Ratio (dB)		
	Weak Desired (−68 dBm)	Moderate Desired (−53 dBm)	Strong Desired (−28 dBm)
N+/−2	≥−44	−40	−20
N+/−3	≥−48	−40	−20
N+/−4	≥−52	−40	−20
N+/−5	≥−56	−42	−20
N+/−6 to N+/−13	≥−57	−45	−20
N +/−14 and N+/−15	≥−46	−45	−20

Notes: ATSC high definition moving video should be used for video source. All DTV values are average power.

13. Burst Noise

Equipment shall tolerate a noise burst of at least 165 µs duration at a 10 Hz repetition rate without visible errors. The noise burst shall be generated by gating a white noise source with average power -5 dB, measured in the 6 MHZ channel under test, referenced to the average power of the DTV signal. The input DTV signal level shall be -28 dBm. Refer to ATSC A/74 Section 4.4.4 for further guidance.

14. Field Ensembles

Equipment shall demonstrate that it can successfully demodulate, with two or fewer errors, 30 of the 50 field ensembles available from ATSC in conjunction with ATSC A/74. Error counts are not expected to include inherent errors associated with the start and end or looping of field ensembles for playback.

Refer to ATSC A/74 Section 4.5.2 for further guidance.

15. Single Static Echo

Equipment shall comply with either **CRITERIA A** or **CRITERIA B**, below.

CRITERIA A:

Equipment shall tolerate a single static echo with the magnitude, relative to a desired DTV signal power of -28 dBm, and delay defined in **TABLE 4**.

CRITERIA B:

Equipment may demonstrate compliance by tolerating a single static echo with the magnitude, relative to a desired DTV signal power of -28 dBm, and delay defined in **TABLE 5**, if the equipment also demonstrates that it can receive 37 of the 50 field ensembles. See **FIELD ENSEMBLES** requirement.

CRITERIA A:

TABLE 4—MAXIMUM SINGLE STATIC ECHO DELAY

Echo Delay	Desired to Echo Ratio
−50 µs	16 dB
−40 µs	12 dB
−20 µs	6 dB
−10 µs	5 dB
−5 µs	2 dB
0 µs	1 dB
10 µs	2 dB
20 µs	3 dB
40 µs	10 dB
50 µs	16 dB

CRITERIA B:

TABLE 5—MINIMUM SINGLE STATIC ECHO DELAY

Echo Delay	Desired to Echo Ratio
−50 µs	16 dB
−40 µs	16 dB
−20 µs	7.5 dB

TABLE 5—MINIMUM SINGLE STATIC ECHO DELAY—Continued

Echo Delay	Desired to Echo Ratio
−10 µs	5 dB
−5 µs	2 dB
0 µs	1 dB
10 µs	2 dB
20 µs	3 dB
40 µs	16 dB
50 µs	16 dB

16. Channel Display

Equipment must display all channels, including multicast channels, broadcast by a digital television station that can be displayed on an analog TV receiver.

17. Closed Captioning, Emergency Alert System (EAS) and Parental Controls (V-Chip)

Equipment must display (1) EAS message broadcast pursuant to 47 CFR § 11.11 of the FCC Rules; (2) parental control information as required by the FCC Rules in 47 CFR § 15.120 and incorporate the EIA/CEA-766-A standard; and (3) Close Captioning information as required by the FCC Rules in 47 CFR § 15.122 and incorporate the CEA 708/608 standard.

18. Remote Control

A remote control to operate the equipment shall be provided with batteries. Standard codes will be used and provided so the consumer can program an existing remote control to, at a minimum, change channels and turn on and off the converter box and the consumer's existing analog television receiver.

19. Audio Outputs

The RF output must be modulated with associated audio program information; the RCA audio connectors must provide stereo left/right, when broadcast.

20. Energy Standards

The equipment shall use no more than two watts of electricity in the ''Sleep'' state. Sleep state power shall be measured in accordance with industry standard CEA-2013-A. Eligible equipment shall provide the capability to automatically switch from the On state to the Sleep state after a period of time without user input. This capability shall be enabled at the factory as the default setting for the device. The default period of inactivity before the equipment automatically switches to the Sleep state shall be four hours. Eligible equipment may allow the current program to complete before switching to the Sleep state. The default energy related settings shall not be altered during the initial user set-up process and shall persist unless the user chooses at a later date to manually: (a) disable the ''automatic switching to Sleep state'' capability, or (b) adjust the default time period from 4 hours to some other value.

21. Owner's manual

An owner's manual shall include information regarding the remote control codes used to permit the consumer to program a universal remote control. The owner's manual will include information regarding the availability of the main audio channel and other associated audio channels on the RF and left/right audio outputs.

22. LED Indicator

The equipment shall contain an LED to indicate when the unit is turned on.

23. RF Cable

The equipment will include at least one RF cable to connect the unit with its associated analog television receiver.

24. Signal Quality Indicator

The equipment will display on the television receiver signal quality indications such as signal strength per ATSC A/74, Section 4.7.

TECHNICAL APPENDIX 2—NTIA Coupon-Eligible Converter Box (CECB): Permitted and Disqualifying Features

Feature	Permitted Feature	Disqualifying Feature
General Requirements		Any device or capability which provides for more than simply converting a digital over-the-air television signal (ATSC) for display on an analog television receiver (NTSC), **including, but not limited to**: Integrated video display; Video or Audio recording or playback capability such as VCR, DVD, HDDVD, Blue Ray, etc.
Antenna Inputs	Smart Antenna interface connector (CEA 909 Smart Antenna Control Interface standard). The manufacturer may supply a 300 ohm connector or a matching transformer to connect 300 ohm ribbon leads to the required RF antenna input.	
Antenna Pass-Through	Equipment may pass through a NTSC analog signal from the antenna to the TV receiver. By-pass switch to permit NTSC pass-through.	
Bundling Antenna and Converter Box	Equipment and Smart Antenna may be sold together at promotional prices.	Equipment cannot be sold conditioned on the purchase of a Smart Antenna or other equipment.
Outputs (General)	S-Video	Digital Video Interface (DVI); Component video (YPbPr); High-Definition Multimedia Interface (HDMI); Computer video (VGA); USB IEEE-1394 (iLink or Firewire) Ethernet (IEEE-802.3) Wireless (IEEE0802.11)

TECHNICAL APPENDIX 2—NTIA Coupon-Eligible Converter Box (CECB): Permitted and Disqualifying Features—Continued

Feature	Permitted Feature	Disqualifying Feature
Outputs (Audio)	Equipment may process associated audio services described in Section 6.6 of A/54. RF output may provide monaural audio for the selected audio channel. RF output may provide BTSC stereo for the selected audio channels.	
Automatic Software Repair/Upgrade	Equipment is able to receive and process software pursuant to ATSC A-97.	
Program Information	Equipment may contain software and hardware modifications necessary to display other program information as determined by the manufacturer.	
Remote Control	Manufacturers may include a programmable universal remote control to operate the equipment and other existing video and audio equipment. Remote control may have dedicated keys to provide direct access to closed captioning and descriptive video functions.	
Other Features	Equipment may be operated on battery power as well as external AC/DC power. Manufacturer may supply additional cables, such as a cable with 3 female RCA connectors for composite video (yellow connector) and stereo left and right audio (white and red connectors). Equipment may display on the television receiver additional signal quality information as determined by the manufacturer.	
Energy Standards	Equipment may comply with standards established by the EPA Energy Star program or state regulatory authorities.	

Dated: March 9, 2007.

John M.R. Kneuer,

Assistant Secretary for Communications and Information Administration.

[FR Doc. E7–4668 Filed 3–14–07; 8:45 am]

BILLING CODE 3510–60–S

DEPARTMENT OF COMMERCE

National Telecommunications and Information Administration

47 CFR Part 301

Digital-to-Analog Converter Box Coupon Program Public Meeting

AGENCY: National Telecommunications and Information Administration, Commerce.

ACTION: Public meeting.

SUMMARY: Summary: NTIA will hold a public meeting on March 19, 2007 in connection with its Digital-to-Analog Converter Box Coupon Program described in the Final Rule that was recently adopted by NTIA.

DATES: The meeting will be held on March 19, 2007 at 10 a.m., Eastern Standard Time.

ADDRESSES: The meeting will be held at the U.S. Department of Commerce Auditorium, 1401 Constitution Avenue, N.W., Washington, D.C.

FOR FURTHER INFORMATION CONTACT: For further information regarding the meeting, contact Sandra Stewart at (202) 482–2246.

SUPPLEMENTARY INFORMATION: NTIA will host a public meeting to discuss its Final Rule establishing the Digital-to-Analog Converter Box Coupon Program. A copy of the Final Rule is available on NTIA's website at *http://www.ntia.doc.gov*. The public meeting will be limited to those issues addressed in the Final Rule. NTIA will not entertain questions related to the Request for Information published by NTIA on July 31, 2006, or other procurement related issues. All procurement-related questions should be directed to Diane Trice at (301) 713–0838 ext. 102 or *diane.trice@noaa.gov*.

Public attendance at the meeting is limited to space available. The meeting will be physically accessible to people with disabilities. Individuals requiring special services, such as sign language interpretation or other ancillary aids, are asked to indicate this to Sandra Stewart at least two (2) days prior to the meeting. Members of the public will have an opportunity to ask questions at the meeting. Individuals who would like to submit written questions should e-mail their questions to Francine Jefferson at *fjefferson@ntia.doc.gov*.

Dated: March 9, 2007.

Kathy D. Smith,

Chief Counsel, National Telecommunications and Information Administration.

[FR Doc. E7–4642 Filed 3–14–07; 8:45 am]

BILLING CODE 3510–60–S

Proposed Rules

Federal Register

Vol. 72, No. 50

Thursday, March 15, 2007

This section of the FEDERAL REGISTER contains notices to the public of the proposed issuance of rules and regulations. The purpose of these notices is to give interested persons an opportunity to participate in the rule making prior to the adoption of the final rules.

OFFICE OF PERSONNEL MANAGEMENT

5 CFR Part 351

RIN 3206–AL19

Representative Rate; Order of Release From Competitive Level; Assignment Rights

AGENCY: Office of Personnel Management.

ACTION: Proposed rule with request for comments.

SUMMARY: The Office of Personnel Management (OPM) is issuing proposed regulations clarifying *representative rate* as used in OPM's retention regulations. These regulations clarify how an agency determines employees' retention rights when the agency has positions in one or more pay bands. These regulations also clarify the order in which an agency releases employees from a competitive level. Finally, these regulations clarify how an agency determines employees' retention rights when a competitive area includes more than one local commuting area.

DATES: We will consider comments received on or before May 14, 2007.

ADDRESSES: You may submit comments, identified by RIN 3206–AL19, by any of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.
- *E-mail: employ@opm.gov.* Include ''RIN 3206–AL19'' in the subject line of the message.
- *Fax:* (202) 606–2329.
- *Mail:* Mark Doboga, Deputy Associate Director for Talent and Capacity Policy, U.S. Office of Personnel Management, Room 6551, 1900 E Street NW., Washington, DC 20415–9700.
- *Hand Delivery/Courier:* OPM, Room 6551, 1900 E Street, NW., Washington, DC 20415.

FOR FURTHER INFORMATION CONTACT: Thomas A. Glennon by telephone on 202–606–0960, by FAX on 202–606–2329, by TDD on 202–418–3134, or by e-mail at *employ@opm.gov.*

SUPPLEMENTARY INFORMATION:

Representative Rate

To determine released competing employees' rights under OPM's reduction in force regulations in part 351 of title 5, Code of Federal Regulations (CFR), an agency may need to compare positions to determine the employee's eligibility to ''bump'' or ''retreat'' to a position in a different pay schedule. When two or more positions are in different pay schedules, the agency compares the representative rate of the positions to determine equivalent grade levels and the best offer of assignment for the released employee.

The agency does not use representative rates to determine released employees' retention standing when all positions are in the same pay schedule. In this situation, the agency directly compares the grades or levels of the positions.

Section 351.203 of OPM's current reduction in force regulations defines *representative rate* as (1) the fourth step of the grade for a position under the General Schedule (GS), (2) the prevailing rate for a position under the Federal Wage System (FWS), or similar wage-determining procedure, and (3) for other positions (e.g., positions in an ungraded pay system, pay band positions, negotiated pay systems), the rate designated by the agency as representative of the position.

OPM proposes to update the definition of *representative rate* in § 351.203 with the following revisions:

1. New paragraph (1) in the definition provides that representative rate is the fourth step of the grade for a position covered by the General Schedule, using the applicable locality rate authorized by 5 U.S.C. 5304 and 5 CFR part 531, subpart F, for GS positions in the 48 contiguous states. If the competitive area includes one local commuting area within a single locality pay area, the agency uses the same locality-adjusted representative rate for all GS positions at the same grade in the competitive area (e.g., all GS–7 positions have the same representative rate without regard to other pay such as special rates). For information, new paragraph (c)(5) of § 351.403 explains that the agency selects a single locality-adjusted representative rate for all GS positions at the same grade when a competitive area includes more than one local commuting area covering more than one locality pay area.

Under the current definition in § 351.203, representative rate for GS positions does not include locality payments authorized by 5 U.S.C. 5304 and 5 CFR part 531, subpart F. In contrast, pay for FWS positions includes a locality component that is defined as basic pay and is included in the current definition of representative rate.

Our proposed change includes locality payments in the representative rate of GS positions located in the 48 contiguous states. This will allow agencies to determine employees' representative rates using a comparable locality component for both GS and FWS positions.

2. New paragraph (2) in the definition continues current policy that representative rate is the prevailing rate for a position covered by an FWS or similar wage-determining procedure.

3. New paragraph (3) in the definition provides that for positions in a pay band, representative rate is the rate the agency designates as representative of that pay band. Consistent with the inclusion of locality payments in the representative rates for GS positions, the proposed regulations also require agencies to include in the representative rate for a pay band any locality payment under 5 U.S.C. 5304 (or equivalent payment under other legal authority) authorized for a position in that pay band for more equitable position comparisons.

For example, the agency could establish a single representative rate for a pay band that includes administrative and support positions that would otherwise be classified from GS–5 through GS–7, or equivalent.

The current definition of *representative rate* in § 351.203 does not specifically address positions in a pay band. At present, for any positions other than GS and FWS (including positions in a banded system), the agency designates a rate that is representative of those positions.

4. New paragraph (4) in the definition provides that for positions not covered by new paragraphs (1) through (3) (e.g., positions in an unclassified or negotiated pay system), the representative rate is the rate the agency designates as representative of the

position. Again, the proposed regulations require agencies to include any locality payment under 5 U.S.C. 5304 (or equivalent payment under other legal authority) that applies to such a position in the representative rate that it designates. At present, as noted previously, for any positions other than GS and FWS (including positions in an unclassified or negotiated pay system), the agency designates a rate that is representative of those positions.

We note that, as under the current reduction in force regulations, the definition of *representative rate* in the proposed regulations is different from the definition of *representative rate* for the purposes of grade and pay retention under 5 CFR 536.103, severance pay under 5 CFR 550.703, and discontinued service retirement under 5 CFR 831.503(b)(3)(iv) and 842.206(c)(3)(iv). As under the current rules, agencies would need to apply each definition separately.

Competitive Level

In § 351.403, we revise paragraph (c)(4) and add new paragraphs (a)(5), (c)(5), and (c)(6).

New paragraph (a)(5) of § 351.403 provides that if a competitive area includes positions in one or more pay bands, each pay band set of interchangeable positions under the competitive level provisions of paragraphs (a)(1) through (4) of 5 CFR 351.403 is a separate competitive level. As appropriate, the entire pay band may be one competitive level, or the pay band may include multiple competitive levels.

For example, a pay band includes positions traditionally classified from GS–4 through GS–7. If the employees' official positions are identical (*i.e.*, identical positions are always interchangeable), the pay band includes one competitive level with one representative rate even though employees' actual salaries may vary under the agency's pay band compensation system. If the pay band includes three official positions that are not interchangeable under the competitive level provisions of paragraphs (a)(1) through (4) of § 351.403, the pay band includes three competitive levels with the agency determining the appropriate representative rate for each level.

New paragraph (c)(5) of § 351.403 provides that an agency does not establish separate reduction in force competitive levels solely on the basis of a difference in GS locality payments under 5 U.S.C. 5304 when a competitive level includes more than one locality pay area listed in § 531.603 of this chapter. If a competitive area includes more than one local commuting area covering more than one locality pay area, the agency establishes GS competitive levels on the basis of the representative rates for one local commuting area and locality pay area within the competitive area. For example, if a competitive area includes GS positions in both Norfolk and Richmond, Virginia, the agency would decide whether to establish GS competitive levels on the basis of the representative rate in Norfolk or the rate in Richmond.

Current paragraph (c)(4) of § 351.403 contains a comparable provision for FWS positions. Revised paragraph (c)(4) clarifies this provision. For example, if a competitive area includes FWS positions in both Pensacola, Florida, and Gulfport, Mississippi, the agency would decide whether to establish FWS competitive levels on the basis of the representative rate in Pensacola or the rate in Gulfport.

New paragraph (c)(6) of § 351.403 provides that if a competitive area includes more than one local commuting area, the agency uses the same local commuting area to establish competitive levels under paragraphs (c)(4) (FWS positions) and (c)(5) (GS positions) of § 351.403. In the example with Norfolk and Richmond, the agency would decide whether to establish all its competitive levels on the basis of representative rates in Norfolk, or the rates in Richmond. The agency may not use one local commuting area in the competitive area to establish representative rates for one pay schedule (e.g., GS), and a different local commuting area in the competitive area to establish representative rates for a different pay schedule (e.g., FWS) used in the same reduction in force.

Release From the Competitive Level

In § 351.601, current paragraph (b) is redesignated paragraph (c), paragraph (a) is revised, and new paragraph (b) is added.

Revised paragraph (a) of § 351.601 clarifies that the agency releases employees from a pay band in the same inverse order of retention standing that the agency releases other employees from a competitive level. New paragraph (b) of § 351.601 clarifies longstanding policy that, at its option, an agency may provide for intervening displacement within the competitive level before final release of the employee with the lowest-retention standing from the competitive level.

Assignment Rights

In § 351.701, paragraph (a) is revised and new paragraphs (g), (h), and (i) are added.

New paragraph (g) of § 351.701 provides that if a competitive area includes more than one local commuting area, the agency determines released employees' assignment rights on the basis of the representative rates for the one local commuting area within the competitive area that the agency used to establish competitive levels under 5 CFR 351.403(c)(4), (5), and (6).

New paragraph (h) explains how the agency determines a released employee's assignment rights when all positions in a competitive area are pay band positions. A released employee has a potential assignment right to a position in an equivalent pay band or one pay band lower. A preference eligible with a service-connected disability of 30 percent or more has a potential assignment right to a position in an equivalent pay band or no more than two pay bands lower. The agency is responsible for determining the scope of assignment rights to other pay bands.

New paragraph (i) explains how the agency determines a released employee's assignment rights when a competitive area includes pay band positions and other positions not covered by a pay band. After the agency determines the representative rates of (1) positions not covered by a pay band (in new (i)(1)) and (2) positions covered by a pay band (in new paragraph (i)(2)), new paragraph (i)(3) provides that the agency applies the representative rate of each pay band position to positions not covered by a pay band to determine the potential assignment rights of employees released by reduction in force from pay band positions.

For example, an agency has a pay band that includes positions traditionally classified from GS–4 through GS–7. The employees' official positions are identical and are otherwise interchangeable for purposes of the competitive level provisions in 5 CFR 351.403(a). Under new paragraph (a)(5) of 5 CFR 351.403, the pay band comprises one competitive level with one representative rate even though employees' actual salaries may vary. The agency would then use the representative rate of the pay band to determine whether employees in positions not included in a pay band have potential assignment rights to positions in the pay band. The agency would also use the representative rate of the pay band to determine whether pay band employees have potential

assignment rights to positions not included in the pay band.

For a second example, an agency again has a pay band that includes positions traditionally classified from GS–4 through GS–7. This time, the pay band includes three different official positions with different salaries. Under new paragraph (a)(5) of § 351.403, the agency finds that the pay band includes three competitive levels, each with its own representative rate. The agency would then use each of the three representative rates of the competitive levels within the pay band to determine whether employees in positions not included in a pay band have potential assignment rights to positions in the pay band. The agency would also use the representative rates of the pay band to determine whether pay band employees have potential assignment rights to positions not included in the pay band.

Regulatory Flexibility Act

I certify that this regulation will not have a significant economic impact on a substantial number of small entities because it affects only certain Federal employees.

Executive Order 12866, Regulatory Review

This rule has been reviewed by the Office of Management and Budget in accordance with Executive Order 12866.

List of Subjects in 5 CFR Part 351

Administrative practice and procedure, Government employees.

Office of Personnel Management.

Linda M. Springer,

Director.

Accordingly, OPM proposes to amend part 351 of title 5, Code of Federal Regulations, as follows:

PART 351—REDUCTION IN FORCE

1. The authority citation for part 351 continues to read as follows:

Authority: 5 U.S.C. 1302, 3502, 3503; sec. 351.801 also issued under E.O. 12828, 58 FR 2965.

2. In § 351.203, the definition of *representative rate* is revised to read as follows:

§ 351.203 Definitions.

In this part:

* * * * *

Representative rate means:

(1) The fourth step of the grade for a position covered by the General Schedule, using the locality rate authorized by 5 U.S.C. 5304 and subpart F of part 531 of this chapter for General Schedule positions;

(2) The prevailing rate for a position covered by a wage-board or similar wage-determining procedure;

(3) For positions in a pay band, the rate (or rates) the agency designates as representative of that pay band or competitive levels within the pay band, including (as appropriate) any applicable locality payment authorized by 5 U.S.C. 5304 and subpart F of part 531 of this chapter (or equivalent payment under other legal authority); and

(4) For other positions (e.g., positions in an unclassified pay system), the rate the agency designates as representative of the position, including (as appropriate) any applicable locality payment authorized by subpart F of part 531 (or equivalent payment under other legal authority).

* * * * *

3. In § 351.403, paragraph (c)(4) is revised, and paragraphs (a)(5), (c)(5), and (c)(6) are added, to read as follows:

§ 351.403 Competitive Level.

(a) * * *

(5) If a competitive area includes positions in one or more pay bands, each set of interchangeable positions in the pay band under paragraphs (a)(1) through (4) of this section is a separate competitive level (e.g., with interchangeable positions under paragraphs (a)(1) through (4) of this section, each pay band is one competitive level; if the positions are not interchangeable under paragraphs (a)(1) through (4) of this section, the pay band may include multiple competitive levels).

* * * * *

(c) * * *

(4) A difference in the local wage areas when a competitive area includes positions covered by more than one wage-board or similar wage-determining procedure;

(5) A difference in locality payments under 5 U.S.C. 5304 and subpart F of part 531 of this chapter when a competitive level includes more than one locality pay area listed in § 531.603 of this chapter; or

(6) Representative rates in different local commuting areas when a competitive area includes General Schedule and wage grade positions in multiple General Schedule locality pay areas, and/or FWS local wage areas.

4. Section 351.601 is revised to read as follows:

§ 351.601 Order of release from competitive level.

(a) Each agency must select competing employees for release from a competitive level (including release from a competitive level involving a pay band) under this part in the inverse order of retention standing, beginning with the employee with the lowest retention standing on the retention register. An agency may not release a competing employee from a competitive level while retaining in that level an employee with lower retention standing except:

(1) As required under § 351.606 when an employee is retained under a mandatory exception or under § 351.806 when an employee is entitled to a new written notice of reduction in force; or

(2) As permitted under § 351.607 when an employee is retained under a permissive continuing exception or under § 351.608 when an employee is retained under a permissive temporary exception.

(b) At its option an agency may provide for intervening displacement within the competitive level before final release of the employee with the lowest-retention standing from the competitive level.

(c) When employees in the same retention subgroup have identical service dates and are tied for release from a competitive level, the agency may select any tied employee for release.

5. In section 351.701, paragraphs (g), (h), and (i) are added, to read as follows:

§ 351.701 Assignment involving displacement.

* * * * *

(g) If a competitive area includes more than one local commuting area, the agency determines assignment rights under this part on the basis of the representative rates for one local commuting area within the competitive area (i.e., the same local commuting area used to establish competitive levels under § 351.403(c)(4), (5), and (6)).

(h) If a competitive area includes positions under one or more pay bands, a released employee shall be assigned in accordance with paragraphs (a) through (d) of this section to a position in an equivalent pay band or one pay band lower, as determined by the agency, than the pay band from which released. A preference eligible with a service-connected disability of 30 percent or more must be assigned in accordance with paragraphs (a) through (d) of this section to a position in an equivalent pay band or up to two pay bands lower, as determined by the agency, than the pay band from which released.

(i) If a competitive area includes positions under one or more pay bands, and other positions not covered by a pay band (e.g., GS and/or FWS positions),

the agency provides assignment rights under this part by:

(1) Determining the representative rate of positions not covered by a pay band consistent with § 351.203;

(2) Determining the representative rate of each pay band, or competitive level within the pay band(s), consistent with § 351.203;

(3) As determined by the agency, providing assignment rights under paragraph (b) of this section (bumping), or paragraphs (c) and (d) of this section (retreating), consistent with the grade intervals covered in paragraphs (b)(2) and (c)(2) of this section, and the pay band intervals in paragraph (h) of this section.

[FR Doc. E7–4701 Filed 3–14–07; 8:45 am]

BILLING CODE 6325–39–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2007–27560; Directorate Identifier 2006–NM–211–AD]

RIN 2120–AA64

Airworthiness Directives; Boeing Model 757–200, –200PF, and –200CB Series Airplanes

AGENCY: Federal Aviation Administration (FAA), Department of Transportation (DOT).

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: The FAA proposes to adopt a new airworthiness directive (AD) for certain Boeing Model 757–200, –200PF, and –200CB series airplanes. This proposed AD would require inspections to detect scribe lines and cracks of the fuselage skin, lap joints, circumferential butt splice strap, and external and internal approved repairs; and related investigative/corrective actions if necessary. This proposed AD results from reports of scribe lines adjacent to the skin lap joints. We are proposing this AD to detect and correct cracks, which could grow and cause rapid decompression of the airplane.

DATES: We must receive comments on this proposed AD by April 30, 2007.

ADDRESSES: Use one of the following addresses to submit comments on this proposed AD.

- *DOT Docket Web site:* Go to *http://dms.dot.gov* and follow the instructions for sending your comments electronically.
- *Government-wide rulemaking Web site:* Go to *http://www.regulations.gov* and follow the instructions for sending your comments electronically.
- *Mail:* Docket Management Facility, U.S. Department of Transportation, 400 Seventh Street, SW., Nassif Building, room PL–401, Washington, DC 20590.
- *Fax:* (202) 493–2251.
- *Hand Delivery:* Room PL–401 on the plaza level of the Nassif Building, 400 Seventh Street, SW., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

Contact Boeing Commercial Airplanes, P.O. Box 3707, Seattle, Washington 98124–2207, for the service information identified in this proposed AD.

FOR FURTHER INFORMATION CONTACT: Dennis Stremick, Aerospace Engineer, Airframe Branch, ANM–120S, FAA, Seattle Aircraft Certification Office, 1601 Lind Avenue, SW., Renton, Washington 98057–3356; telephone (425) 917–6450; fax (425) 917–6590.

SUPPLEMENTARY INFORMATION:

Comments Invited

We invite you to submit any relevant written data, views, or arguments regarding this proposed AD. Send your comments to an address listed in the **ADDRESSES** section. Include the docket number ''FAA–2007–27560; Directorate Identifier 2006–NM–211–AD'' at the beginning of your comments. We specifically invite comments on the overall regulatory, economic, environmental, and energy aspects of the proposed AD. We will consider all comments received by the closing date and may amend the proposed AD in light of those comments.

We will post all comments we receive, without change, to *http://dms.dot.gov*, including any personal information you provide. We will also post a report summarizing each substantive verbal contact with FAA personnel concerning this proposed AD. Using the search function of that Web site, anyone can find and read the comments in any of our dockets, including the name of the individual who sent the comment (or signed the comment on behalf of an association, business, labor union, etc.). You may review DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (65 FR 19477–78), or you may visit *http://dms.dot.gov*.

Examining the Docket

You may examine the AD docket on the Internet at *http://dms.dot.gov*, or in person at the Docket Management Facility office between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The Docket Management Facility office (telephone (800) 647–5227) is located on the plaza level of the Nassif Building at the DOT street address stated in the **ADDRESSES** section. Comments will be available in the AD docket shortly after the Docket Management System receives them.

Discussion

We have received reports of scribe lines found adjacent to the skin lap joints on Model 757–200 airplanes. The scribe lines appear to have been made on the skin when sealant was removed as part of preparation of the airplane for repainting. The airplanes had between 13,300 and 16,800 flight cycles. Although no cracks as a result of scribe lines have been reported on Model 757 airplanes, scribe lines have caused cracks on other airplanes. Undetected cracking, if not corrected, could grow and result in rapid decompression.

Related AD

This proposed AD is similar to AD 2006–07–12, amendment 39–14539 (71 FR 16211), March 31, 2006. That AD applies to all Boeing Model 737–100, –200, –200C, –300, –400, and –500 series airplanes. That AD requires a one-time inspection for scribe lines and cracks in the fuselage skin at certain lap joints, butt joints, external repair doublers, and other areas; and related investigative/corrective actions if necessary. That AD resulted from reports of fuselage skin cracks adjacent to the skin lap joints on airplanes that had scribe lines.

Relevant Service Information

We have reviewed Boeing Alert Service Bulletin 757–53A0092, Revision 1, dated January 10, 2007. The service bulletin describes procedures for removing paint and sealant at the applicable zonal locations, and doing detailed inspections to detect scribe lines and cracks of the fuselage skin, lap joints, circumferential butt splice strap, and external and internal approved repairs. The service bulletin specifies repairing scribe lines before further flight, except when a limited return to service (LRTS) program for qualifying scribe lines would allow return to service for a limited period before scribe lines are repaired.

The LRTS program includes repetitive inspections to detect cracks where scribe lines were found. To qualify for an LRTS program, a scribe line must meet certain criteria including the total flight cycles on the airplane, and the location and extent of the scribe lines.

The service bulletin specifies contacting Boeing for final repair instructions for the LRTS program, which would eliminate the need for the repetitive inspections of the LRTS program. The repetitive intervals for the LRTS program range from 1,500 to 8,000 flight cycles, depending on the location of the scribe lines and the configuration of the airplane.

Each piece of structure susceptible to a scribe line is assigned to a zone. Based on criticality of location, the service bulletin addresses the most critical areas (zones) first and appropriately reduces the compliance requirements for less critical areas. The service bulletin has specific instructions for calculating separate inspection thresholds. These thresholds are based on (1) fatigue life for the identified zonal locations and (2) potential scribe line opportunities in an airplane's maintenance history. The compliance times for inspecting are 20,000 flight cycles (Zone 1) and 30,000 flight cycles (Zone 2) after the first scribe opportunity. If a maintenance records-based threshold program is not used, however, the service bulletin specifies 6,000 flight cycles as the first scribe opportunity. Since a scribe line can occur at any time during the service life of an airplane and at many locations, the service bulletin uses both total flight cycles and structural criticality of locations to determine the inspection requirements.

FAA's Determination and Requirements of the Proposed AD

We have evaluated all pertinent information and identified an unsafe condition that is likely to exist or develop on other airplanes of this same type design. For this reason, we are proposing this AD, which would require accomplishing the actions specified in the service information described previously, except as discussed below.

Differences Between the Proposed AD and Service Information

The service bulletin specifies to contact the manufacturer for instructions on how to repair certain conditions, but this proposed AD would require repairing those conditions by using a method that we approve, or by using data that meet the certification basis of the airplane, and that have been approved by an Authorized Representative for the Boeing Commercial Airplanes Delegation Option Authorization Organization whom we have authorized to make those findings.

The service bulletin specifies compliance times relative to the date of issuance of the service bulletin; however, this proposed AD would require compliance before the specified compliance time relative to the effective date of the AD.

Costs of Compliance

There are about 945 airplanes of the affected design in the worldwide fleet; of these, about 634 are U.S.-registered airplanes. The following table provides the estimated costs for U.S. operators to comply with this proposed AD. There are no U.S.-registered airplanes in Group 5 or Group 6.

ESTIMATED COSTS

Inspections	Work hours	Average labor rate per hour	Cost per airplane	Number of U.S.-registered airplanes	Fleet cost
Group 1	127	$80	$10,160	144	$1,463,040
Group 2	122	80	9,760	6	58,560
Group 3	154	80	12,320	75	924,000
Group 4	128	80	10,240	409	4,188,160

Authority for This Rulemaking

Title 49 of the United States Code specifies the FAA's authority to issue rules on aviation safety. Subtitle I, section 106, describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes in more detail the scope of the Agency's authority.

We are issuing this rulemaking under the authority described in subtitle VII, part A, subpart III, section 44701, "General requirements." Under that section, Congress charges the FAA with promoting safe flight of civil aircraft in air commerce by prescribing regulations for practices, methods, and procedures the Administrator finds necessary for safety in air commerce. This regulation is within the scope of that authority because it addresses an unsafe condition that is likely to exist or develop on products identified in this rulemaking action.

Regulatory Findings

We have determined that this proposed AD would not have federalism implications under Executive Order 13132. This proposed AD would not have a substantial direct effect on the States, on the relationship between the national Government and the States, or on the distribution of power and responsibilities among the various levels of government.

For the reasons discussed above, I certify that the proposed regulation:

1. Is not a "significant regulatory action" under Executive Order 12866;

2. Is not a "significant rule" under the DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and

3. Will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

We prepared a regulatory evaluation of the estimated costs to comply with this proposed AD and placed it in the AD docket. See the **ADDRESSES** section for a location to examine the regulatory evaluation.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Safety.

The Proposed Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA proposes to amend 14 CFR part 39 as follows:

PART 39—AIRWORTHINESS DIRECTIVES

1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

2. The Federal Aviation Administration (FAA) amends § 39.13 by adding the following new airworthiness directive (AD):

Boeing: Docket No. FAA–2007–27560; Directorate Identifier 2006–NM–211–AD.

Comments Due Date

(a) The FAA must receive comments on this AD action by April 30, 2007.

Affected ADs

(b) None.

Applicability

(c) This AD applies to Boeing Model 757–200, –200PF, and –200CB series airplanes, certificated in any category; as identified in Boeing Alert Service Bulletin 757–53A0092, Revision 1, dated January 10, 2007.

Unsafe Condition

(d) This AD results from reports of scribe lines adjacent to the fuselage skin lap joints. We are issuing this AD to detect and correct cracks, which could grow and cause rapid decompression of the airplane.

Compliance

(e) You are responsible for having the actions required by this AD performed within the compliance times specified, unless the actions have already been done.

Inspections

(f) Perform detailed inspections to detect scribe lines and cracks of the fuselage skin, lap joints, circumferential butt splice strap, and external and internal approved repairs; and perform related investigative and corrective actions. Do the actions in accordance with the Accomplishment Instructions of Boeing Alert Service Bulletin 757–53A0092, Revision 1, dated January 10, 2007, except as required by paragraph (g) of this AD. Do the actions within the applicable compliance times specified in paragraph 1.E. of the service bulletin, except as required by paragraph (h) of this AD.

Exceptions to Service Bulletin Specifications

(g) Where Boeing Alert Service Bulletin 757–53A0092, Revision 1, dated January 10, 2007, specifies to contact Boeing for appropriate repair instructions, repair using a method approved in accordance with the procedures specified in paragraph (j) of this AD.

(h) Boeing Alert Service Bulletin 757–53A0092, Revision 1, dated January 10, 2007, specifies compliance times relative to the date of issuance of the service bulletin; however, this proposed AD would require compliance before the specified compliance time relative to the effective date of the AD.

Credit for Prior Accomplishment

(i) Inspections done before the effective date of this AD in accordance with Boeing Alert Service Bulletin 757–53A0092, dated September 18, 2006, are acceptable for compliance with the corresponding requirements of paragraph (f) of this AD.

Alternative Methods of Compliance (AMOCs)

(j)(1) The Manager, Seattle Aircraft Certification Office (ACO), FAA, has the authority to approve AMOCs for this AD, if requested in accordance with the procedures found in 14 CFR 39.19.

(2) Before using any AMOC approved in accordance with § 39.19 on any airplane to which the AMOC applies, notify the appropriate principal inspector in the FAA Flight Standards Certificate Holding District Office.

(3) An AMOC that provides an acceptable level of safety may be used for any repair required by this AD, if it is approved by an Authorized Representative for the Boeing Commercial Airplanes Delegation Option Authorization Organization who has been authorized by the Manager, Seattle ACO, to make those findings. For a repair method to be approved, the repair must meet the certification basis of the airplane.

Issued in Renton, Washington, on March 1, 2007.

Ali Bahrami,

Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. E7–4742 Filed 3–14–07; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2007–27565; Directorate Identifier 2006–NM–215–AD]

RIN 2120–AA64

Airworthiness Directives; Airbus Model A330 and A340–200 Airplanes

AGENCY: Federal Aviation Administration (FAA), Department of Transportation (DOT).

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: The FAA proposes to supersede an existing airworthiness directive (AD) that applies to certain Airbus Model A330–200, A330–300, A340–200, and A340–300 series airplanes; and Model A340–541 and –642 airplanes. The existing AD currently requires repetitively resetting the display units (DUs) for the electronic instrument system (EIS), either by switching them off and back on again or by performing a complete electrical shutdown of the airplane. This proposed AD would require installing new software, which would end the actions required by the existing AD. This proposed AD also would add additional airplanes that may be placed on the U.S. Register in the future. This proposed AD results from an incident in which all of the DUs for the EIS went blank simultaneously during flight. We are proposing this AD to prevent automatic reset of the DUs for the EIS during flight and consequent loss of data from the DUs, which could reduce the ability of the flightcrew to control the airplane during adverse flight conditions.

DATES: We must receive comments on this proposed AD by April 16, 2007.

ADDRESSES: Use one of the following addresses to submit comments on this proposed AD.

- *DOT Docket Web site:* Go to *http://dms.dot.gov* and follow the instructions for sending your comments electronically.
- *Government-wide rulemaking Web site:* Go to *http://www.regulations.gov* and follow the instructions for sending your comments electronically.
- *Mail:* Docket Management Facility; U.S. Department of Transportation, 400 Seventh Street, SW., Nassif Building, Room PL–401, Washington, DC 20590.
- *Fax:* (202) 493–2251.
- *Hand Delivery:* Room PL–401 on the plaza level of the Nassif Building, 400 Seventh Street, SW., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

Contact Airbus, 1 Rond Point Maurice Bellonte, 31707 Blagnac Cedex, France, for service information identified in this proposed AD.

FOR FURTHER INFORMATION CONTACT: Tim Backman, Aerospace Engineer, International Branch, ANM–116, Transport Airplane Directorate, FAA, 1601 Lind Avenue, SW., Renton, Washington 98057–3356; telephone (425) 227–2797; fax (425) 227–1149.

SUPPLEMENTARY INFORMATION:

Comments Invited

We invite you to submit any relevant written data, views, or arguments regarding this proposed AD. Send your comments to an address listed in the **ADDRESSES** section. Include the docket number ''Docket No. FAA–2007–27565; Directorate Identifier 2006–NM–215–AD'' at the beginning of your comments. We specifically invite comments on the overall regulatory, economic, environmental, and energy aspects of the proposed AD. We will consider all comments received by the closing date and may amend the proposed AD in light of those comments.

We will post all comments we receive, without change, to *http://dms.dot.gov,* including any personal information you provide. We will also post a report summarizing each substantive verbal contact with FAA personnel concerning this proposed AD. Using the search function of that Web site, anyone can find and read the comments in any of our dockets, including the name of the individual who sent the comment (or signed the comment on behalf of an association, business, labor union, etc.). You may review the DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (65 FR 19477–78), or you may visit *http://dms.dot.gov.*

Examining the Docket

You may examine the AD docket on the Internet at *http://dms.dot.gov,* or in person at the Docket Management Facility office between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The Docket Management Facility office (telephone (800) 647–5227) is located on the plaza level of the Nassif Building at the DOT street address stated in the ADDRESSES section. Comments will be available in the AD docket shortly after the Docket Management System receives them.

Discussion

On August 18, 2005, we issued AD 2005–17–18, amendment 39–14239 (70 FR 50166, August 26, 2005), for certain Airbus Model A330–200, A330–300, A340–200, and A340–300 series airplanes; and Model A340–541 and –642 airplanes. That AD requires repetitively resetting the display units (DUs) for the electronic instrument system (EIS), either by switching them off and back on again or by performing a complete electrical shutdown of the airplane. That AD resulted from an incident in which all of the DUs for the EIS went blank simultaneously during flight. We issued that AD to prevent automatic reset of the DUs for the EIS during flight and consequent loss of data from the DUs, which could reduce the ability of the flightcrew to control the airplane during adverse flight conditions.

Actions Since Existing AD Was Issued

After the issuance of AD 2005–17–18, the Direction Générale de l'Aviation Civile (DGAC), which is the airworthiness authority for France, issued French emergency airworthiness directive UF–2005–166, dated September 23, 2005, which was superseded by F–2005–166 R1, dated October 26, 2005. Those French airworthiness directives cancelled French airworthiness directive UF–2005–150, dated August 10, 2005 (referred to in AD 2005–17–18), and required that the resets be done only by the aircraft flightcrew in accordance with Airbus A330 Airplane Flight Manual (AFM) Temporary Revision (TR) 4.03.00/26 and A340 AFM TR 4.03.00/37, both dated October 11, 2005; as applicable. We determined at that time that further rulemaking was not necessary, because AD 2005–17–18 adequately addresses the unsafe condition by requiring the resets to be done either by certificated maintenance personnel or by the flightcrew. In addition, we approved TRs 4.03.00/26 and 4.03.00/37 as alternative methods of compliance (AMOC) to the requirements of paragraph (f) of AD 2005–17–18 (addressed in paragraph (j)(3) of this proposed AD).

In the preamble to AD 2005–17–18, we specified that the actions required by that AD were considered ''interim action'' and that the manufacturer was developing a modification to address the unsafe condition. We indicated that we may consider further rulemaking once the modification was developed, approved, and available. The manufacturer now has developed such a modification, and we now have determined that further rulemaking action is indeed necessary; this proposed AD follows from that determination.

Relevant Service Information

Airbus has issued the primary service bulletins in the following table:

PRIMARY SERVICE BULLETINS

Airbus Service Bulletin—	For Model—
A330–31–3087, dated June 26, 2006	A330–201, –202, –203, –223, –243, –301, –302, –303, –321, –322, –323, –341, –342, and –343 airplanes.
A340–31–4100, dated June 26, 2006	A340–211, –212, –213, –311, –312, and –313 airplanes.
A340–31–5021, dated June 26, 2006	A340–541 and –642 airplanes.

These primary service bulletins describe procedures for installing electronic instrument system 2 (EIS2) software standard L6–1, which would end the actions required by AD 2005–17–18.

Airbus also has issued the service bulletins in the following table:

ADDITIONAL SERVICE BULLETINS

Airbus Service Bulletin—	Describes procedures for—	Which must be done prior to the actions specified in Airbus Service Bulletin—
A330–31–3069, Revision 01, dated December 27, 2004.	Installing EIS2 software standard L5	A330–31–3087, dated June 26, 2006.
A330–31–3056, Revision 02, dated March 24, 2003.	Installing Thales display system standard L4	A330–31–3087, dated June 26, 2006.
A340–31–4087, Revision 01, dated December 27, 2004.	Installing EIS2 software standard L5	A340–31–4100, dated June 26, 2006.
A340–31–5012, Revision 01, dated December 27, 2004.	Installing EIS2 software standard L5	A340–31–5021, dated June 26, 2006.

Accomplishing the actions specified in the service information is intended to adequately address the unsafe condition. The European Aviation Safety Agency (EASA), which is the Technical Agent for the Member States of the European Union, mandated the service information and issued EASA airworthiness directive 2006–0196, dated July 10, 2006 (which cancels French airworthiness directive F–2005–166 R1), to ensure the continued airworthiness of these airplanes in the European Union.

FAA's Determination and Requirements of the Proposed AD

These airplane models are manufactured in France and are type certificated for operation in the United States under the provisions of section 21.29 of the Federal Aviation Regulations (14 CFR 21.29) and the applicable bilateral airworthiness

agreement. Pursuant to this bilateral airworthiness agreement, the EASA has kept the FAA informed of the situation described above. We have examined the EASA's findings, evaluated all pertinent information, and determined that AD action is necessary for airplanes of this type design that are certificated for operation in the United States.

This proposed AD would supersede AD 2005–17–18 and would retain the requirements of the existing AD. This proposed AD would also require accomplishing the actions specified in service bulletins described previously, which would end the repetitive actions required by AD 2005–17–18. This proposed AD also would add additional airplanes that are subject to the identified unsafe condition of this proposed AD and that may be placed on the U.S. Register in the future.

Difference Between the EASA Airworthiness Directive and This Proposed AD

The applicability of EASA airworthiness directive 2006–0196 excludes certain airplanes on which Airbus Service Bulletin A330–31–3087, A340–31–4100, or A340–31–5021 has been done in service. However, we have not excluded those airplanes in the applicability of this proposed AD; rather, this proposed AD includes a requirement to accomplish the actions specified in the original issue of those service bulletins. This requirement would ensure that the actions specified in the service bulletins and required by this proposed AD are accomplished on all affected airplanes. Operators must continue to operate the airplane in the configuration required by this proposed AD unless an AMOC is approved.

Costs of Compliance

The following table provides the estimated costs for U.S. operators to comply with this proposed AD. The average labor rate per hour is $80.

ESTIMATED COSTS

Action	Work hour(s)	Parts	Cost per airplane	Number of U.S.-registered airplanes	Fleet cost
Resetting the DUs (required by AD 2005–17–18).	1	None	$80, per reset	27	$2,160, per reset.
Installation of new software (new proposed action).	3	The manufacturer states that it will supply required parts to the operators at no cost.	$240	27	$6,480.
Additional requirement (new proposed action).	Between 1 and 5 depending on the airplane configuration.	The manufacturer states that it will supply required parts to the operators at no cost.	Between $80 and $400, depending on the airplane configuration.	27	Between $2,160 and $10,800, depending on the configuration of the fleet.

Authority for This Rulemaking

Title 49 of the United States Code specifies the FAA's authority to issue rules on aviation safety. Subtitle I, Section 106, describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes in more detail the scope of the Agency's authority.

We are issuing this rulemaking under the authority described in Subtitle VII, Part A, Subpart III, Section 44701, "General requirements." Under that section, Congress charges the FAA with promoting safe flight of civil aircraft in air commerce by prescribing regulations for practices, methods, and procedures the Administrator finds necessary for safety in air commerce. This regulation is within the scope of that authority because it addresses an unsafe condition that is likely to exist or develop on products identified in this rulemaking action.

Regulatory Findings

We have determined that this proposed AD would not have federalism implications under Executive Order 13132. This proposed AD would not have a substantial direct effect on the States, on the relationship between the national Government and the States, or on the distribution of power and responsibilities among the various levels of government.

For the reasons discussed above, I certify that the proposed regulation:

1. Is not a "significant regulatory action" under Executive Order 12866;
2. Is not a "significant rule" under the DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and
3. Will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

We prepared a regulatory evaluation of the estimated costs to comply with this proposed AD and placed it in the AD docket. See the **ADDRESSES** section for a location to examine the regulatory evaluation.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Safety.

The Proposed Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA proposes to amend 14 CFR part 39 as follows:

PART 39—AIRWORTHINESS DIRECTIVES

1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

2. The Federal Aviation Administration (FAA) amends § 39.13 by removing amendment 39–14239 (70 FR 50166, August 26, 2005) and adding the following new airworthiness directive (AD):

Airbus: Docket No. FAA–2007–27565; Directorate Identifier 2006–NM–215–AD.

Comments Due Date

(a) The FAA must receive comments on this AD action by April 16, 2007.

Affected ADs

(b) This AD supersedes AD 2005–17–18.

Applicability

(c) This AD applies to Airbus Model A330 and A340 airplanes; certificated in any category; on which one of the Airbus Electronic Instrument System 2 (EIS2) software versions listed in Table 1 of this AD

is installed; excluding those airplanes on which Airbus Modification 53063 has been done in production.

TABLE 1.—APPLICABILITY

EIS2 software version	Installed by this Airbus modification in production	Or installed by one of these Airbus service bulletins in service
L4–1	51153	A330–31–3056, A330–31–3057, or A340–31–5001.
L5	51974	A330–31–3056, A330–31–3069, A340–31–4087, or A340–31–5012.

Unsafe Condition

(d) This AD results from an incident in which all of the display units (DUs) for the EIS went blank simultaneously during flight. We are issuing this AD to prevent automatic reset of the DUs for the EIS during flight and consequent loss of data from the DUs, which could reduce the ability of the flightcrew to control the airplane during adverse flight conditions.

Compliance

(e) You are responsible for having the actions required by this AD performed within the compliance times specified, unless the actions have already been done.

Requirements of AD 2005–17–18

Resetting the DUs for the EIS

(f) For Model A330–201, –202, –203, –223, –243, –301, –321, –322, –323, –341, –342, and –343 airplanes; and Model A340–211, –212, –213, –311, –312, –313, –541, and –642 airplanes: Within 2 days after September 12, 2005 (the effective date of AD 2005–17–18), or within 4 days after the last reset of the DUs for the EIS or complete electrical shutdown of the airplane, whichever is first: Reset the DUs for the EIS by doing the actions in either paragraph (f)(1) or (f)(2) of this AD. Thereafter, do the actions in paragraph (f)(1) or (f)(2) of this AD at intervals not to exceed 4 days.

(1) Switch off each DU for the EIS, wait 5 seconds or longer, and switch the DU back on again, in accordance with Airbus All Operator Telex (AOT) A330–31A3092 (for Model A330–201, –202, –203, –223, –243, –301, –321, –322, –323, –341, –342, and –343 airplanes), A340–31A4102 (for A340–211, –212, –213, –311, –312, and –313 airplanes), or A340–31A5023 (for Model A340–541 and –642 airplanes), all dated August 1, 2005, as applicable. This action may be performed by the flight deck crew or by certificated maintenance personnel.

(2) Perform a complete electrical shutdown of the airplane.

New Requirements of This AD

Installation of New Software

(g) For airplanes other than those identified in paragraph (f) of this AD: Within 2 days after the effective date of this AD, or within 4 days after the last reset of the DUs for the EIS or complete electrical shutdown of the airplane, whichever is first, do the reset specified in paragraph (f) of this AD and repeat thereafter at intervals not to exceed 4 days, until the installation required by paragraph (h) of this AD has been done.

(h) For all airplanes: Within 7 months after the effective date of this AD, install EIS2 software standard L6–1 in accordance with the applicable service bulletin identified in Table 2 of this AD. Accomplishing the installation ends the actions required by paragraphs (f) and (g) of this AD.

TABLE 2.—SERVICE BULLETINS FOR INSTALLATION OF NEW SOFTWARE

Airbus service bulletin—	For model—
(1) A330–31–3087, dated June 26, 2006	A330–201, –202, –203, –223, –243, –301, –302, –303, –321, –322, –323, –341, –342, and –343 airplanes.
(2) A340–31–4100, dated June 26, 2006	A340–211, –212, –213, –311, –312, and –313 airplanes.
(3) A340–31–5021, dated June 26, 2006	A340–541 and –642 airplanes.

Additional Requirements

(i) Prior to accomplishing the requirements specified in paragraph (g) of this AD, do the applicable action(s) specified in Table 3 of this AD.

TABLE 3.—ADDITIONAL REQUIREMENTS

For airplanes identified in—	Install—	In accordance with Airbus service bulletin—
(1) Paragraph (h)(1) of this AD	(i) EIS2 software standard L5	A330–31–3069, Revision 01, dated December 27, 2004.
	(ii) Thales display system standard L4	A330–31–3056, Revision 02, dated March 24, 2003.
(2) Paragraph (h)(2) of this AD	EIS2 software standard L5	A340–31–4087, Revision 01, dated December 27, 2004.
(3) Paragraph (h)(3) of this AD	EIS2 software standard L5	A340–31–5012, Revision 01, dated December 27, 2004.

Alternative Methods of Compliance (AMOCs)

(j)(1) The Manager, International Branch, ANM–116, Transport Airplane Directorate, FAA, has the authority to approve AMOCs for this AD, if requested in accordance with the procedures found in 14 CFR 39.19.

(2) Before using any AMOC approved in accordance with § 39.19 on any airplane to which the AMOC applies, notify the appropriate principal inspector in the FAA Flight Standards Certificate Holding District Office.

(3) AMOCs approved previously in accordance with AD 2005–17–18 are approved as AMOCs for the corresponding provisions of paragraph (f) of this AD.

Related Information

(k) European Aviation Safety Agency airworthiness directive 2006–0196, dated July 10, 2006, also addresses the subject of this AD.

Issued in Renton, Washington, on March 7, 2007.

Ali Bahrami,

Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. E7–4741 Filed 3–14–07; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2007–27212; Directorate Identifier 2007–CE–011–AD]

RIN 2120–AA64

Airworthiness Directives; Air Tractor, Inc. Models AT–602, AT–802, and AT–802A Airplanes

AGENCY: Federal Aviation Administration (FAA), Department of Transportation (DOT).

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: We propose to supersede Airworthiness Directive (AD) 2006–22–08, which applies to all Air Tractor, Inc. (Air Tractor) Models AT–602, AT–802, and AT–802A airplanes. AD 2006–22–08 currently requires you to repetitively inspect the engine mount for any cracks, repair or replace any cracked engine mount, and report any cracks found to the FAA. Since we issued AD 2006–22–08, the FAA has received reports of two Model AT–802A airplanes with cracked engine mounts (at 2,815 hours time-in-service (TIS) and 1,900 hours TIS) below the initial compliance time in AD 2006–22–08. The FAA has determined that an initial inspection at 1,300 hours TIS is required instead of 4,000 hours TIS required by AD 2006–22–08. Consequently, this proposed AD would retain the actions of AD 2006–22–08 while requiring the initial inspection at 1,300 hours TIS. We are proposing this AD to detect and correct cracks in the engine mount, which could result in failure of the engine mount. Such failure could lead to separation of the engine from the airplane.

DATES: We must receive comments on this proposed AD by May 14, 2007.

ADDRESSES: Use one of the following addresses to comment on this proposed AD:

• *DOT Docket Web site:* Go to *http://dms.dot.gov* and follow the instructions for sending your comments electronically.

• *Mail:* Docket Management Facility; U.S. Department of Transportation, 400 Seventh Street, SW., Nassif Building, Room PL–401, Washington, DC 20590–0001.

• *Fax:* (202) 493–2251.

• *Hand Delivery:* Room PL–401 on the plaza level of the Nassif Building, 400 Seventh Street, SW., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

• *Federal eRulemaking Portal:* Go to *http://www.regulations.gov.* Follow the instructions for submitting comments.

For service information identified in this proposed AD, contact Air Tractor, Inc., P.O. Box 485, Olney, Texas 76374; telephone: (940) 564–5616; facsimile: (940) 564–5612.

FOR FURTHER INFORMATION CONTACT: Andrew McAnaul, Aerospace Engineer, ASW–150 (c/o MIDO–43), 10100 Reunion Place, Suite 650, San Antonio, Texas 78216; telephone: (210) 308–3365; facsimile: (210) 308–3370.

SUPPLEMENTARY INFORMATION:

Comments Invited

We invite you to send any written relevant data, views, or arguments regarding this proposed AD. Send your comments to an address listed under the **ADDRESSES** section. Include the docket number, ‘‘FAA–2007–27212; Directorate Identifier 2007–CE–011–AD’’ at the beginning of your comments. We specifically invite comments on the overall regulatory, economic, environmental, and energy aspects of the proposed AD. We will consider all comments received by the closing date and may amend the proposed AD in light of those comments.

We will post all comments we receive, without change, to *http://dms.dot.gov,* including any personal information you provide. We will also post a report summarizing each substantive verbal contact we receive concerning this proposed AD.

Discussion

Two reports from Air Tractor of cracked engine mounts resulting from fatigue caused us to issue AD 2006–22–08, Amendment 39–14805 (71 FR 62910, October 27, 2006). AD 2006–22–08 currently requires the following on all Air Tractor Models AT–602, AT–802, and AT–802A airplanes:

• Inspect (initially and repetitively) the engine mount for any cracks;

• Repair or replace any cracked engine mount; and

• Report any cracks found to the FAA.

Since we issued AD 2006–22–08, the FAA has received reports of two Model AT–802A airplanes with cracked engine mounts (at 2,815 hours TIS and 1,900 hours TIS) below the initial compliance time in AD 2006–22–08. The FAA has determined that an initial inspection at 1,300 hours TIS is required instead of 4,000 hours TIS as required by AD 2006–22–08.

This condition, if not corrected, could result in failure of the engine mount. Such failure could lead to separation of the engine from the airplane.

Relevant Service Information

We have reviewed Snow Engineering Co. Service Letter #253, dated December 12, 2005, revised January 22, 2007.

The service information describes procedures for performing a visual inspection for cracks of the engine mount and requesting a repair scheme from the manufacturer.

Snow Engineering Co. has a licensing agreement with Air Tractor that allows them to produce technical data to use for Air Tractor products.

FAA's Determination and Requirements of the Proposed AD

We are proposing this AD because we evaluated all information and determined the unsafe condition described previously is likely to exist or develop on other products of the same type design. This proposed AD would supersede AD 2006–22–08 with a new AD that would require you to repetitively inspect the engine mount for any cracks, repair or replace any cracked engine mount, and report any cracks found to the FAA. To repair a cracked engine mount, you would obtain an FAA-approved repair scheme from Air Tractor following the instructions in the service information.

This proposed AD would require you to use the service information described previously to perform these actions.

Costs of Compliance

We estimate that this AD affects 368 airplanes in the U.S. registry.

We estimate the following costs to do each required inspection:

Labor cost	Parts cost	Total cost per airplane per inspection	Total cost on U.S. operators for initial inspection
1.5 work-hours × $80 per hour = $120	Not Applicable.	$120	$44,160

We have no way of determining the number of airplanes that may need replacement of the engine mount. We estimate the following costs to do the replacement:

Labor cost	Parts cost	Total cost per airplane per replacement
81 work-hours × $80 per hour = $6,480	$3,982	$10,462

Any required ''upon-condition'' repairs would vary depending upon the damage found during each inspection. Based on this, we have no way of determining the potential repair costs for each airplane.

Authority for This Rulemaking

Title 49 of the United States Code specifies the FAA's authority to issue rules on aviation safety. Subtitle I, Section 106, describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes in more detail the scope of the Agency's authority.

We are issuing this rulemaking under the authority described in Subtitle VII, Part A, Subpart III, Section 44701, ''General requirements.'' Under that section, Congress charges the FAA with promoting safe flight of civil aircraft in air commerce by prescribing regulations for practices, methods, and procedures the Administrator finds necessary for safety in air commerce. This regulation is within the scope of that authority because it addresses an unsafe condition that is likely to exist or develop on products identified in this rulemaking action.

Regulatory Findings

We have determined that this proposed AD would not have federalism implications under Executive Order 13132. This proposed AD would not have a substantial direct effect on the States, on the relationship between the national Government and the States, or on the distribution of power and responsibilities among the various levels of government.

For the reasons discussed above, I certify that the proposed regulation:

1. Is not a ''significant regulatory action'' under Executive Order 12866;
2. Is not a ''significant rule'' under the DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and
3. Will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

We prepared a regulatory evaluation of the estimated costs to comply with this proposed AD and placed it in the AD docket.

Examining the AD Docket

You may examine the AD docket that contains the proposed AD, the regulatory evaluation, any comments received, and other information on the Internet at *http://dms.dot.gov;* or in person at the Docket Management Facility between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The Docket Office (telephone (800) 647–5227) is located at the street address stated in the **ADDRESSES** section. Comments will be available in the AD docket shortly after receipt.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Safety.

The Proposed Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA proposes to amend 14 CFR part 39 as follows:

PART 39—AIRWORTHINESS DIRECTIVES

1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

2. The FAA amends § 39.13 by removing Airworthiness Directive (AD) 2006–22–08, Amendment 39–14805 (71 FR 62910, October 27, 2006), and adding the following new AD:

Air Tractor, Inc: Docket No. FAA–2007–27212; Directorate Identifier 2007–CE–011–AD.

Comments Due Date

(a) We must receive comments on this airworthiness directive (AD) action by May 14, 2007.

Affected ADs

(b) This AD supersedes AD 2006–22–08, Amendment 39–14805.

Applicability

(c) This AD affects all Models AT–602, AT–802, and AT–802A airplanes, all serial numbers, that are certificated in any category.

Unsafe Condition

(d) This AD results from reports of two Model AT–802A airplanes with cracked engine mounts (at 2,815 hours time-in-service (TIS) and 1,900 hours TIS) below the initial compliance time in AD 2006–22–08. The FAA has determined that an initial inspection at 1,300 hours TIS is required instead of 4,000 hours TIS as required by AD 2006–22–08. We are issuing this AD to detect and correct cracks in the engine mount, which could result in failure of the engine mount. Such failure could lead to separation of the engine from the airplane.

Compliance

(e) To address this problem, you must do the following, unless already done:

Actions	Compliance	Procedures
(1) Visually inspect the engine mount for any cracks.	Initially inspect upon accumulating 1,300 hours TIS or within the next 100 hours TIS after the effective date of this AD, whichever occurs later, unless already done. Thereafter, inspect repetitively at intervals not to exceed 300 hours TIS.	Follow Snow Engineering Co. Service Letter #253, dated December 12, 2005, revised January 22, 2007.
(2) If you find any crack damage, do the following: (i) Obtain an FAA-approved repair scheme or replacement procedure from the manufacturer; and (ii) Repair following the FAA-approved repair scheme or replace the engine mount with a new engine mount following the replacement procedure.	Before further flight after any inspection required by paragraph (e)(1) of this AD where crack damage is found. If you repair the cracked engine mount, then continue to reinspect at intervals not to exceed 300 hours TIS, unless the repair scheme states differently. If you replace the engine mount, then initially inspect upon accumulating 1,300 hours TIS and repetitively at intervals not to exceed 300 hours TIS.	*For obtaining a repair scheme or replacement procedure:* Contact Air Tractor Inc., P.O. Box 485, Olney, Texas 76374; telephone: (940) 564–5616; facsimile: (940) 564–5612.
(3) Report any cracks that you find to the FAA at the address specified in paragraph (f) of this AD. Include in your report: (i) Airplane serial number; (ii) Airplane hours TIS and engine mount hours TIS; (iii) Crack location(s) and size(s); (iv) Corrective action taken; and (v) Point of contact name and telephone number.	Within the next 30 days after you find the cracks or within the next 30 days after the effective date of this AD, whichever occurs later.	The Office of Management and Budget (OMB) approved the information collection requirements contained in this regulation under the provisions of the Paperwork Reduction Act of 1980 (44 U.S.C. 3501 et seq.) and assigned OMB Control Number 2120–0056.

Alternative Methods of Compliance (AMOCs)

(f) The Manager, Fort Worth Airplane Certification Office, FAA, ATTN: Andrew McAnaul, Aerospace Engineer, ASW–150 (c/o MIDO–43), 10100 Reunion Place, Suite 650, San Antonio, Texas 78216; telephone: (210) 308–3365; facsimile: (210) 308–3370, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19. Before using any approved AMOC on any airplane to which the AMOC applies, notify your appropriate principal inspector (PI) in the FAA Flight Standards District Office (FSDO), or lacking a PI, your local FSDO.

(g) AMOCs approved for AD 2006–22–08 are not approved for this AD.

Related Information

(h) To get copies of the service information referenced in this AD, contact Air Tractor Inc., P.O. Box 485, Olney, Texas 76374; telephone: (940) 564–5616; facsimile: (940) 564–5612. To view the AD docket, go to the Docket Management Facility; U.S. Department of Transportation, 400 Seventh Street, SW., Nassif Building, Room PL–401, Washington, DC, or on the Internet at *http://ms.dot.gov.* The docket number is Docket No. FAA–2007–27212; Directorate Identifier 2007–CE–011–AD.

Issued in Kansas City, Missouri, on March 8, 2007.

David R. Showers,

Acting Manager, Small Airplane Directorate, Aircraft Certification Service.

[FR Doc. E7–4737 Filed 3–14–07; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2007–27213; Directorate Identifier 2007–CE–012–AD]

RIN 2120–AA64

Airworthiness Directives; British Aerospace Regional Aircraft Model HP.137 Jetstream Mk.1, Jetstream Series 200, Jetstream Series 3101, and Jetstream Model 3201 Airplanes

AGENCY: Federal Aviation Administration (FAA), Department of Transportation (DOT).

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: We propose to adopt a new airworthiness directive (AD) for the products listed above that would supersede an existing AD. This proposed AD results from mandatory continuing airworthiness information (MCAI) originated by an aviation authority of another country to identify and correct an unsafe condition on an aviation product. The MCAI describes the unsafe condition as:

Cracking has been found in the nose landing gear steering jack piston rod adjacent to the eye-end. This was caused by the application of excessive tightening torque applied to the eye-end whilst being assembled during component overhaul. Failure of the steering jack piston during operation will result in loss of nose wheel steering, which may lead to loss of directional control during critical phases of take-off and landing.

The proposed AD would require actions that are intended to address the unsafe condition described in the MCAI.

DATES: We must receive comments on this proposed AD by April 16, 2007.

ADDRESSES: You may send comments by any of the following methods:

• *DOT Docket Web Site:* Go to *http://dms.dot.gov* and follow the instructions for sending your comments electronically.

• *Fax:* (202) 493–2251.

• *Mail:* Docket Management Facility, U.S. Department of Transportation, 400 Seventh Street, SW., Nassif Building, Room PL–401, Washington, DC 20590–0001.

• *Hand Delivery:* Room PL–401 on the plaza level of the Nassif Building, 400 Seventh Street, SW., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

• *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.

Examining the AD Docket

You may examine the AD docket on the Internet at *http://dms.dot.gov;* or in person at the Docket Management Facility between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains this proposed AD, the regulatory evaluation, any comments received, and other information. The street address for the Docket Office (telephone (800) 647–5227) is in the **ADDRESSES** section.

Comments will be available in the AD docket shortly after receipt.

FOR FURTHER INFORMATION CONTACT: Taylor Martin, Aerospace Engineer, FAA, Small Airplane Directorate, 901 Locust, Room 301, Kansas City, Missouri 64106; telephone: (816) 329–4138; fax: (816) 329–4090.

SUPPLEMENTARY INFORMATION:

Streamlined Issuance of AD

The FAA is implementing a new process for streamlining the issuance of ADs related to MCAI. This streamlined process will allow us to adopt MCAI safety requirements in a more efficient manner and will reduce safety risks to the public. This process continues to follow all FAA AD issuance processes to meet legal, economic, Administrative Procedure Act, and **Federal Register** requirements. We also continue to meet our technical decision-making responsibilities to identify and correct unsafe conditions on U.S.-certificated products.

This proposed AD references the MCAI and related service information that we considered in forming the engineering basis to correct the unsafe condition. The proposed AD contains text copied from the MCAI and for this reason might not follow our plain language principles.

Comments Invited

We invite you to send any written relevant data, views, or arguments about this proposed AD. Send your comments to an address listed under the **ADDRESSES** section. Include ''Docket No. FAA–2007–27213; Directorate Identifier 2007–CE–012–AD'' at the beginning of your comments. We specifically invite comments on the overall regulatory, economic, environmental, and energy aspects of this proposed AD. We will consider all comments received by the closing date and may amend this proposed AD because of those comments.

We will post all comments we receive, without change, to *http://dms.dot.gov,* including any personal information you provide. We will also post a report summarizing each substantive verbal contact we receive about this proposed AD.

Discussion

On March 25, 2003, we issued AD 2003–07–06, Amendment 39–13102 (68 FR 16195, April 3, 2003). That AD required actions intended to address an unsafe condition on the products listed above.

Since we issued AD 2003–07–06, following the completion of their testing, the equipment manufacturer has determined that the fatigue life needs further revision (reduction) and has published inspection criteria and a revised formula for calculating the piston safe life. This calculation and a revised end fitting tightening torque are contained in Revision 1 to APPH Ltd. Service Bulletin 32–76. As a result, pistons, which were previously calculated to have significant remaining life, may now be unserviceable.

The Civil Aviation Authority, which is the aviation authority for the United Kingdom, has issued AD No. G–2004–0029, dated December 20, 2004 (referred to after this as ''the MCAI''), to correct an unsafe condition for the specified products. The MCAI states:

Cracking has been found in the nose landing gear steering jack piston rod adjacent to the eye-end. This was caused by the application of excessive tightening torque applied to the eye-end whilst being assembled during component overhaul. Failure of the steering jack piston during operation will result in loss of nose wheel steering, which may lead to loss of directional control during critical phases of take-off and landing.

The MCAI requires:

The inspections and any required rectification actions detailed in BAe Systems Service Bulletin 32–JA030644 and associated APPH Service Bulletin 32–76 Revision 1 are required to be performed to ensure continued airworthiness of the aircraft.

You may obtain further information by examining the MCAI in the AD docket.

Relevant Service Information

BAE Systems has issued British Aerospace Jetstream Series 3100 & 3200 Service Bulletin 32–JA030644, dated October 6, 2003. APPH Ltd. has issued Service Bulletin 32–76, Revision 1, dated August 2003. The actions described in this service information are intended to correct the unsafe condition identified in the MCAI.

FAA's Determination and Requirements of the Proposed AD

This product has been approved by the aviation authority of another country, and is approved for operation in the United States. Pursuant to our bilateral agreement with this State of Design Authority, they have notified us of the unsafe condition described in the MCAI and service information referenced above. We are proposing this AD because we evaluated all information and determined the unsafe condition exists and is likely to exist or develop on other products of the same type design.

Differences Between This Proposed AD and the MCAI or Service Information

We have reviewed the MCAI and related service information and, in general, agree with their substance. But we might have found it necessary to use different words from those in the MCAI to ensure the AD is clear for U.S. operators and is enforceable. In making these changes, we do not intend to differ substantively from the information provided in the MCAI and related service information.

We might also have proposed different actions in this AD from those in the MCAI in order to follow FAA policies. Any such differences are highlighted in a NOTE within the proposed AD.

Costs of Compliance

Based on the service information, we estimate that this proposed AD would affect about 190 products of U.S. registry. We also estimate that it would take about 2 work-hours per product to comply with the basic requirements of this proposed AD. The average labor rate is $80 per work-hour.

Based on these figures, we estimate the cost of the proposed AD on U.S. operators to be $30,400, or $160 per product.

In addition, we estimate that any necessary follow-on actions would take about 8 work-hours and require parts costing $5,300, for a cost of $5,940 per product. We have no way of determining the number of products that may need these actions.

Authority for This Rulemaking

Title 49 of the United States Code specifies the FAA's authority to issue rules on aviation safety. Subtitle I, section 106, describes the authority of the FAA Administrator. ''Subtitle VII: Aviation Programs,'' describes in more detail the scope of the Agency's authority.

We are issuing this rulemaking under the authority described in ''Subtitle VII, Part A, Subpart III, Section 44701: General requirements.'' Under that section, Congress charges the FAA with promoting safe flight of civil aircraft in air commerce by prescribing regulations for practices, methods, and procedures the Administrator finds necessary for safety in air commerce. This regulation is within the scope of that authority because it addresses an unsafe condition that is likely to exist or develop on products identified in this rulemaking action.

Regulatory Findings

We determined that this proposed AD would not have federalism implications

under Executive Order 13132. This proposed AD would not have a substantial direct effect on the States, on the relationship between the national Government and the States, or on the distribution of power and responsibilities among the various levels of government.

For the reasons discussed above, I certify this proposed regulation:

1. Is not a ''significant regulatory action'' under Executive Order 12866;

2. Is not a ''significant rule'' under the DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and

3. Will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

We prepared a regulatory evaluation of the estimated costs to comply with this proposed AD and placed it in the AD docket.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Safety.

The Proposed Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA proposes to amend 14 CFR part 39 as follows:

PART 39—AIRWORTHINESS DIRECTIVES

1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

2. The FAA amends § 39.13 by removing Airworthiness Directive (AD) 2003–07–06, Amendment 39–13102 (68 FR 16195, April 3, 2003), and adding the following new AD:

British Aerospace Regional Aircraft: Docket No. FAA–2007–27213; Directorate Identifier 2007–CE–012–AD.

Comments Due Date

(a) We must receive comments by April 16, 2007.

Affected ADs

(b) Supersedes AD 2003–07–06, Amendment 39–13102.

Applicability

(c) This AD applies to Model HP.137 Jetstream Mk.1, Jetstream Series 200, Jetstream Series 3101, and Jetstream Model 3201 airplanes, all serial numbers, certificated in any category.

Subject

(d) Air Transport Association of America (ATA) Code 32: Landing Gear.

Reason

(e) The mandatory continuing airworthiness information (MCAI) states:

Cracking has been found in the nose landing gear steering jack piston rod adjacent to the eye-end. This was caused by the application of excessive tightening torque applied to the eye-end whilst being assembled during component overhaul. Failure of the steering jack piston during operation will result in loss of nose wheel steering, which may lead to loss of directional control during critical phases of take-off and landing.

Retained Requirements of AD 2003–07–06

(f) Unless already done, do the following actions in accordance with the procedures in APPH Ltd. Service Bulletin 32–76 (pages 1, 2, and 4 through 7, dated October 2002; and page 3, Erratum 1, dated November 2002), as referenced in BAe Systems British Aerospace Jetstream Mandatory Service Bulletin 32–JA020741, Original Issue: November 2, 2002; or APPH Ltd. Service Bulletin 32–76, Revision 1, dated August 2003, as referenced in BAe Systems British Aerospace Jetstream Mandatory Service Bulletin 32–JA030644, Original Issue: October 6, 2003.

(1) Within the next 90 days or 200 ground-air-ground (GAG) cycles after May 22, 2003 (the effective date of AD 2003–07–06), whichever occurs first, inspect the steering jack piston rod for cracks.

(2) If cracks are found, replace the cracked steering jack piston rod. Install the new steering jack piston rod using a torque setting of 175 lbf (pound force) inch or 20 Nm (Newton meters) when tightening the end fitting and stop bolt.

(3) If no cracks are found, determine the torque setting of the steering jack piston rod end fitting and stop bolt.

New Requirements of This AD: Actions and Compliance

(g) Unless already done, do the following actions:

(1) Within 90 days after the effective date of this AD, recalculate the safe life of the steering jack piston rod and re-torque the piston rod eye-end in accordance with APPH Ltd. Service Bulletin 32–76, Revision 1, dated August 2003, as referenced in paragraph 2, Part 2 of BAe Systems Service Bulletin 32–JA030644, dated October 6, 2003.

(2) If the piston rod is found unserviceable when inspected in accordance with APPH Ltd. Service Bulletin 32–76, Revision 1, dated August 2003, as referenced in paragraph 2, Part 2 of BAe Systems Service Bulletin 32–JA030644, dated October 6, 2003, before further flight remove the steering jack and replace with a serviceable unit.

(3) As of the effective date of this AD, before a steering jack piston rod is installed, it must be inspected and the safe life determined in accordance APPH Ltd. Service Bulletin 32–76, Revision 1, dated August 2003, as referenced in paragraph 2 of BAe Systems Service Bulletin 32–JA030644, dated October 6, 2003.

FAA AD Differences

Note: This AD differs from the MCAI and/or service information as follows: No differences.

Other FAA AD Provisions

(h) The following provisions also apply to this AD:

(1) *Alternative Methods of Compliance (AMOCs):* The Manager, Standards Staff, FAA, Small Airplane Directorate, ATTN: Taylor Martin, Aerospace Engineer, 901 Locust, Room 301, Kansas City, Missouri 64106; telephone: (816) 329–4138; fax: (816) 329–4090, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19. Before using any approved AMOC on any airplane to which the AMOC applies, notify your appropriate principal inspector (PI) in the FAA Flight Standards District Office (FSDO), or lacking a PI, your local FSDO.

(2) AMOCs approved for AD 2003–07–06 are not approved for this AD.

(3) *Airworthy Product:* For any requirement in this AD to obtain corrective actions from a manufacturer or other source, use these actions if they are FAA-approved. Corrective actions are considered FAA-approved if they are approved by the State of Design Authority (or their delegated agent). You are required to assure the product is airworthy before it is returned to service.

(4) *Reporting Requirements:* For any reporting requirement in this AD, under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*), the Office of Management and Budget (OMB) has approved the information collection requirements and has assigned OMB Control Number 2120–0056.

Related Information

(i) Refer to MCAI Civil Aviation Authority AD No. G–2004–0029, dated December 20, 2004; BAE Systems British Aerospace Jetstream Series 3100 & 3200 Service Bulletin 32–JA030644, dated October 6, 2003; BAe Systems British Aerospace Jetstream Mandatory Service Bulletin 32–JA020741, Original Issue: November 2, 2002; APPH Ltd. Service Bulletin 32–76, Revision 1, dated August 2003; and APPH Ltd. Service Bulletin 32–76 (pages 1, 2, and 4 through 7, dated October 2002; and page 3, Erratum 1, dated November 2002, for related information.

Issued in Kansas City, Missouri, on March 8, 2007.

David R. Showers,

Acting Manager, Small Airplane Directorate, Aircraft Certification Service.

[FR Doc. E7–4739 Filed 3–14–07; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2007–27525; Directorate Identifier 2006–NM–159–AD]

RIN 2120–AA64

Airworthiness Directives; Boeing Model 747–100, 747–100B, 747–100B SUD, 747–200B, 747–200C, 747–300, 747–400, 747–400D, 747SR, and 747SP Series Airplanes

AGENCY: Federal Aviation Administration (FAA), Department of Transportation (DOT).

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: The FAA proposes to supersede an existing airworthiness directive (AD) that applies to certain Boeing Model 747 airplanes. The existing AD currently requires repetitive inspections to detect cracks and/or corrosion of the girt bar support fitting at certain main entry doors (MED), and repair or replacement of the support fitting. The existing AD also provides for various terminating actions for the repetitive inspections. This proposed AD would require the following additional actions: An inspection, for certain airplanes, for correct installation of square and conical washers in the girt bar support fitting; an inspection, for certain other airplanes, to determine if the washers are installed; and related investigative and corrective action if necessary. This proposed AD results from a report that the square and conical washers may be installed incorrectly in the girt bar support fitting on airplanes on which the support fitting was repaired or replaced in accordance with the requirements of the existing AD. We are proposing this AD to detect and correct corrosion of the girt bar support fitting, which could result in separation of the escape slide from the lower door sill during deployment, and subsequently prevent proper operation of the escape slides at the main entry doors during an emergency. We are also proposing this AD to detect and correct incorrect installation of the square and conical washers in the girt bar support fitting, which could result in failure of the escape slide when deployed.

DATES: We must receive comments on this proposed AD by April 30, 2007.

ADDRESSES: Use one of the following addresses to submit comments on this proposed AD.

- *DOT Docket Web site:* Go to *http://dms.dot.gov* and follow the instructions for sending your comments electronically.
- *Government-wide rulemaking Web site:* Go to *http://www.regulations.gov* and follow the instructions for sending your comments electronically.
- *Mail:* Docket Management Facility; U.S. Department of Transportation, 400 Seventh Street SW., Nassif Building, room PL–401, Washington, DC 20590.
- *Fax:* (202) 493–2251.
- *Hand Delivery:* Room PL–401 on the plaza level of the Nassif Building, 400 Seventh Street SW., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

Contact Boeing Commercial Airplanes, P.O. Box 3707, Seattle, Washington 98124–2207, for service information identified in this proposed AD.

FOR FURTHER INFORMATION CONTACT: Patrick Gillespie, Aerospace Engineer, Cabin Safety and Environmental Systems Branch, ANM–150S, FAA, Seattle Aircraft Certification Office, 1601 Lind Avenue, SW., Renton, Washington 98057–3356; telephone (425) 917–6429; fax (425) 917–6590.

SUPPLEMENTARY INFORMATION:

Comments Invited

We invite you to submit any relevant written data, views, or arguments regarding this proposed AD. Send your comments to an address listed in the **ADDRESSES** section. Include the docket number ''Docket No. FAA–2007–27525; Directorate Identifier 2006–NM–159–AD'' at the beginning of your comments. We specifically invite comments on the overall regulatory, economic, environmental, and energy aspects of the proposed AD. We will consider all comments received by the closing date and may amend the proposed AD in light of those comments.

We will post all comments we receive, without change, to *http://dms.dot.gov*, including any personal information you provide. We will also post a report summarizing each substantive verbal contact with FAA personnel concerning this proposed AD. Using the search function of that web site, anyone can find and read the comments in any of our dockets, including the name of the individual who sent the comment (or signed the comment on behalf of an association, business, labor union, etc.). You may review the DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (65 FR 19477–78), or you may visit *http://dms.dot.gov.*

Examining the Docket

You may examine the AD docket on the Internet at *http://dms.dot.gov,* or in person at the Docket Management Facility office between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The Docket Management Facility office (telephone (800) 647–5227) is located on the plaza level of the Nassif Building at the DOT street address stated in the **ADDRESSES** section. Comments will be available in the AD docket shortly after the Docket Management System receives them.

Discussion

On October 31, 1996, we issued AD 96–23–05, amendment 39–9810 (61 FR 58318, November 14, 1996), for certain Boeing Model 747 series airplanes. That AD requires repetitive inspections to detect cracks and/or corrosion of the girt bar support fitting at certain main entry doors (MED); and repair or replacement of the support fitting. That AD also provides for various terminating actions for the repetitive inspections. That AD resulted from reports that, during scheduled deployment tests of main entry door slides, corrosion was found on the floor structure supports for the escape slides of the main deck entry doors on these airplanes. We issued that AD to prevent such corrosion, which could result in separation of the escape slide from the lower door sill during deployment, and subsequently prevent proper operation of the escape slides at the main entry doors during an emergency.

Actions Since Existing AD Was Issued

Since we issued AD 96–23–05, Boeing has determined that the square and conical washers may be installed incorrectly in the girt bar support fitting on airplanes on which the support fitting was repaired or replaced in accordance with Boeing Service Bulletin 747–53A2378, dated June 24, 1993; Revision 1, dated March 10, 1994; or Revision 2, dated July 24, 2003 (Revision 1 of the service bulletin was referenced as the appropriate source of service information for doing the actions specified in AD 96–23–05).

Relevant Service Information

We have reviewed Boeing Service Bulletin 747–53A2378, Revision 3, dated August 11, 2005. The service bulletin contains essentially the same procedures for the actions described in the earlier revisions of the service bulletin, but Revision 3 revises the procedures for the installation of the square and conical washers on the girt bar support fitting.

Revision 3 also adds actions for airplanes on which the support fitting was replaced or repaired in accordance with any earlier revision of the service bulletin:

- For Groups 7, 8, and 9 airplanes identified in the service bulletin: Do an inspection for correct installation of square and conical washers in the girt bar floor fitting, related investigative action, and corrective actions. The related investigative action is an inspection of the bolts and washers for damage. The corrective actions include installing the square and conical washers correctly and contacting the manufacturer if damage is found.
- For Groups 1 through 6 airplanes identified in the service bulletin: Do an inspection to check if square and conical washers are installed in the girt bar floor fitting, related investigative actions, and corrective actions. The related investigative actions include doing an inspection for correct installation of square and conical washers in the girt bar floor fitting and an inspection of the bolts and washers for damage. The corrective actions include installing the square and conical washers correctly and contacting the manufacturer if damage is found.

Accomplishing the actions specified in the service information is intended to adequately address the unsafe condition.

FAA's Determination and Requirements of the Proposed AD

We have evaluated all pertinent information and identified an unsafe condition that is likely to develop on other airplanes of the same type design. For this reason, we are proposing this AD, which would supersede AD 96–23–05 and would retain the requirements of the existing AD. This proposed AD would also require the following actions for airplanes on which the support fitting was repaired or replaced in accordance with Boeing Service Bulletin 747–53A2378, dated June 24, 1993; Revision 1, dated March 10, 1994; or Revision 2, dated July 24, 2003: An inspection, for certain airplanes, for correct installation of square and conical washers in the girt bar support fitting; an inspection, for certain other airplanes, to determine if the washers are installed; and related investigative and corrective action if necessary.

Differences Between the Proposed AD and the Service Bulletin

Although Boeing Service Bulletin 747–53A2378 specifies that operators may contact the manufacturer if certain damage is found, this proposed AD would require operators to repair those conditions using a method approved by the FAA.

Although Boeing Service Bulletin 747–53A2378, Revision 3, specifies doing certain actions if Boeing Service Bulletin 747–53A2378, dated June 24, 1993; Revision 1, dated March 10, 1994; or Revision 2, dated July 24, 2003; was accomplished, this proposed AD would require those actions to also be done if Boeing Service Bulletin 747–25A2831, dated August 29, 1991, was accomplished. Paragraph (m) of AD 96–23–05 allows installation of the girt bar fitting in accordance with Boeing Service Bulletin 747–25A2831 as an acceptable method of compliance. Therefore, installations done in accordance with Boeing Service Bulletin 747–25A2831 should also be inspected for incorrect installation of the square and conical washers in the girt bar support fitting.

Change to Existing AD

This proposed AD would retain all requirements of AD 96–23–05. Since AD 96–23–05 was issued, the AD format has been revised, and certain paragraphs have been rearranged. As a result, the corresponding paragraph identifiers have changed in this proposed AD, as listed in the following table:

REVISED PARAGRAPH IDENTIFIERS

Requirement in AD 96–23–05	Corresponding requirement in this proposed AD
Note 1	paragraph (f).
paragraph (a)	paragraph (g).
paragraph (b)	paragraph (h).
paragraph (c)	paragraph (i).
paragraph (d)	paragraph (j).
paragraph (e)	paragraph (k).
paragraph (f)	paragraph (l).
paragraph (g)	paragraph (m).
paragraph (h)	paragraph (n).
paragraph (i)	paragraph (o).
paragraph (j)	paragraph (p).
paragraph (k)	paragraph (q).
paragraph (l)	paragraph (r).
paragraph (m)	paragraph (s).

Note 2 and paragraph (o) of AD 96–23–05 have been removed from this proposed AD. On July 10, 2002, the FAA issued a new version of 14 CFR part 39 (67 FR 47997, July 22, 2002), which governs the FAA's airworthiness directives system. The regulation now includes material that relates to altered products and alternative methods of compliance (AMOCs), as well as special flight permits (e.g., ferry flights).

Clarification of Doors Affected by the Proposed AD

We have also revised Note 1 of AD 96–23–05, which has the corresponding requirement in paragraph (f) of this proposed AD. We have added the statement "the requirements of this AD are also not applicable to doors on airplanes converted to an all-cargo configuration."

Explanation of Change to Applicability

We have revised the applicability of the existing AD to identify model designations as published in the most recent type certificate data sheet for the affected models. Special freighters are not identified in the type certificate data sheet so the phrase "special freighters" has been removed from the applicability. However, as stated previously, we have added a statement to exempt doors on airplanes converted to an all-cargo configuration.

Explanation of Change Made to Existing Requirements

We have changed all references to a "detailed visual inspection" in the existing AD to "detailed inspection" in this proposed AD.

Clarification of Alternative Method of Compliance (AMOC) Paragraph

We have revised this action to clarify the appropriate procedure for notifying the principal inspector before using any approved AMOC on any airplane to which the AMOC applies.

Costs of Compliance

There are about 1,012 airplanes of the affected design in the worldwide fleet. The following table provides the estimated costs for U.S. operators to comply with this proposed AD. The average labor rate per hour is $80. The cost varies depending on the configuration of the airplane.

ESTIMATED COSTS

Action	Work hours	Cost per airplane	Number of U.S.-registered airplanes	Fleet cost
Inspection of MEDs (required by AD 96–23–05).	Between 88 and 102	Between $7,040 and $8,160, per inspection cycle.	169	Between $1,189,760 and $1,379,040, per inspection cycle.
Inspection for correct installation (new proposed action).	6	$480	Up to 169	Up to $81,120.

Authority for This Rulemaking

Title 49 of the United States Code specifies the FAA's authority to issue rules on aviation safety. Subtitle I, Section 106, describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes in more detail the scope of the Agency's authority.

We are issuing this rulemaking under the authority described in Subtitle VII, Part A, Subpart III, Section 44701, ''General requirements.'' Under that section, Congress charges the FAA with promoting safe flight of civil aircraft in air commerce by prescribing regulations for practices, methods, and procedures the Administrator finds necessary for safety in air commerce. This regulation is within the scope of that authority because it addresses an unsafe condition that is likely to exist or develop on products identified in this rulemaking action.

Regulatory Findings

We have determined that this proposed AD would not have federalism implications under Executive Order 13132. This proposed AD would not have a substantial direct effect on the States, on the relationship between the National Government and the States, or on the distribution of power and responsibilities among the various levels of government.

For the reasons discussed above, I certify that the proposed regulation:

1. Is not a ''significant regulatory action'' under Executive Order 12866;

2. Is not a ''significant rule'' under the DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and

3. Will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

We prepared a regulatory evaluation of the estimated costs to comply with this proposed AD and placed it in the AD docket. See the **ADDRESSES** section for a location to examine the regulatory evaluation.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Safety.

The Proposed Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA proposes to amend 14 CFR part 39 as follows:

PART 39—AIRWORTHINESS DIRECTIVES

1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

2. The Federal Aviation Administration (FAA) amends § 39.13 by removing amendment 39–9810 (61 FR 58318, November 14, 1996) and adding the following new airworthiness directive (AD):

Boeing: Docket No. FAA–2007–27525; Directorate Identifier 2006–NM–159–AD.

Comments Due Date

(a) The FAA must receive comments on this AD action by April 30, 2007.

Affected ADs

(b) This AD supersedes AD 96–23–05.

Applicability

(c) This AD applies to Boeing Model 747–100, 747–100B, 747–100B SUD, 747–200B, 747–200C, 747–300, 747–400, 747–400D, 747SR, and 747SP series airplanes, certificated in any category, line numbers 1 through 868 inclusive.

Unsafe Condition

(d) This AD results from reports that, during scheduled deployment tests of main entry door slides, corrosion was found on the floor structure supports for the escape slides of the main deck entry doors on these airplanes. This AD also results from a report that the square and conical washers may be installed incorrectly in the girt bar support fitting on airplanes on which the support fitting was repaired or replaced in accordance with the requirements of AD 96–23–05. We are issuing this AD to detect and correct corrosion of the girt bar support fitting, which could result in separation of the escape slide from the lower door sill during deployment, and subsequently prevent proper operation of the escape slides at the main entry doors during an emergency. We are also issuing this AD to detect and correct incorrect installation of the square and conical washers in the girt bar support fitting, which could result in failure of the escape slide when deployed.

Compliance

(e) You are responsible for having the actions required by this AD performed within the compliance times specified, unless the actions have already been done.

Restatement of Requirements of AD 96–23–05 With New Service Information

Doors Exempt From/Affected by This AD

(f) The requirements of this AD are not applicable to doors where an escape slide or slide/raft is not installed or is not used for passenger egress (such as a deactivated door 3, at doors 4 and/or 5 of an airplane being operated in the ''combi'' configuration, or any door not used for passenger egress in a ''convertible'' (an airplane configured for quick change from passenger to cargo)). The requirements of this AD are also not applicable to doors on airplanes converted to an all-cargo configuration. The requirements of this AD become applicable at the time when an escape slide or slide/raft is installed on such doors, or when such doors are activated and/or converted for passenger use. The requirements also become applicable at the time an airplane operating in an all-cargo configuration is converted to a passenger or passenger/cargo configuration.

Inspections and Corrective Actions for Airplanes Equipped With Main Entry Door (MED) 1

(g) For airplanes equipped with MED 1: Prior to the accumulation of 16 years of service since date of manufacture of the airplane, or within 18 months after December 16, 1996 (the effective date of AD 96–23–05), whichever occurs later, perform a detailed inspection to detect cracking and/or corrosion of the girt bar support fitting at the left and right MED 1, in accordance with Boeing Service Bulletin 747–53A2378, Revision 1, dated March 10, 1994; or Boeing Service Bulletin 747–53A2378, Revision 3, dated August 11, 2005. After the effective date of this AD, only Revision 3 may be used.

(h) If no cracking or corrosion is found during the inspection required by paragraph (g) of this AD, prior to further flight, accomplish either paragraph (h)(1) or (h)(2) of this AD, in accordance with the applicable instructions specified in Boeing Service Bulletin 747–53A2378, Revision 1, dated March 10, 1994; or Boeing Service Bulletin

747–53A2378, Revision 3, dated August 11, 2005. After the effective date of this AD, only Revision 3 may be used.

(1) Install a new fitting with new fasteners, and reinstall the threshold assembly with new corrosion-resistant fasteners, in accordance with the service bulletin. After these actions are accomplished, no further action is required by paragraph (h) of this AD; or

(2) Reinstall the threshold assembly with corrosion-resistant fasteners, in accordance with the service bulletin. Thereafter, repeat the inspection required by paragraph (g) of this AD at intervals not to exceed 6 years.

(i) If any cracking is found during the inspection required by paragraph (g) or (h)(2) of this AD, prior to further flight, install a new fitting with new fasteners, and reinstall the threshold assembly with new corrosion-resistant fasteners, in accordance with Boeing Service Bulletin 747–53A2378, Revision 1, dated March 10, 1994; or Boeing Service Bulletin 747–53A2378, Revision 3, dated August 11, 2005. After the effective date of this AD, only Revision 3 may be used. After these actions are accomplished, no further action is required by this paragraph.

(j) If any corrosion is found during the inspection required by paragraph (g) or (h)(2) of this AD, prior to further flight, accomplish either paragraph (j)(1) or (j)(2) of this AD, in accordance with Boeing Service Bulletin 747–53A2378, Revision 1, dated March 10, 1994; or Boeing Service Bulletin 747–53A2378, Revision 3, dated August 11, 2005. After the effective date of this AD, only Revision 3 may be used.

(1) Install a new fitting with new fasteners, and reinstall the threshold assembly with new corrosion-resistant fasteners in accordance with the service bulletin. After these actions are accomplished, no further action is required by this paragraph; or

(2) Blend out corrosion in accordance with the service bulletin.

(i) If blend out of corrosion is beyond 10 percent of original thickness or any crack is found during accomplishment of the blend out procedures, install a new fitting with new fasteners, and reinstall the threshold assembly with new corrosion-resistant fasteners, in accordance with the service bulletin. After these actions are accomplished, no further action is required by this paragraph.

(ii) If blend out of corrosion does not exceed 10 percent of original material thickness, accomplish either paragraph (j)(2)(ii)(A) or (j)(2)(ii)(B) of this AD:

(A) Install a new fitting with new fasteners, and reinstall threshold assembly with new corrosion-resistant fasteners, in accordance with the service bulletin. After these actions are accomplished, no further action is required by this paragraph; or

(B) Install the repaired fitting with new fasteners and reinstall the threshold assembly with corrosion-resistant fasteners, in accordance with the service bulletin. Thereafter, repeat the inspection and applicable corrective actions required by paragraph (g) of this AD at intervals not to exceed 6 years.

Inspections and Corrective Actions for Airplanes Equipped With MED 2, 4, and/or 5 (MED 2, 3, and/or 4 on Model 747SP Series Airplanes)

(k) For airplanes equipped with MED 2, 4, and/or 5 (MED 2, 3, and/or 4 on Model 747SP series airplanes): Prior to the accumulation of 10 years of service since date of manufacture of the airplane, or within 18 months after December 16, 1996, whichever occurs later, perform a detailed inspection to detect cracking and/or corrosion of the girt bar support fitting at the left and right MED 2, 4, and 5 (MED 2, 3, and 4 on Model 747SP series airplanes), in accordance with Boeing Service Bulletin 747–53A2378, Revision 1, dated March 10, 1994; or Boeing Service Bulletin 747–53A2378, Revision 3, dated August 11, 2005. After the effective date of this AD, only Revision 3 may be used.

(l) If no cracking or corrosion is found during the inspection required by paragraph (k) of this AD, prior to further flight, accomplish either paragraph (l)(1) or (l)(2) of this AD, in accordance with the applicable instructions in Boeing Service Bulletin 747–53A2378, Revision 1, dated March 10, 1994; or Boeing Service Bulletin 747–53A2378, Revision 3, dated August 11, 2005. After the effective date of this AD, only Revision 3 may be used.

(1) Remove the inspected fitting and reinstall it with a new coat of primer and new fasteners; and reinstall the threshold assembly with new corrosion-resistant fasteners; in accordance with the service bulletin. After these actions are accomplished, no further action is required by this paragraph; or

(2) Reinstall the serrated plate assembly and the girt bar floor fitting with corrosion-resistant fasteners, in accordance with the service bulletin. Thereafter, repeat the inspection required by paragraph (k) of this AD at intervals not to exceed 6 years.

(m) If any cracking is found during the inspection required by paragraph (k) or (l)(2) of this AD, prior to further flight, install a new fitting with new fasteners, and reinstall the threshold assembly with new corrosion-resistant fasteners, in accordance with Boeing Service Bulletin 747–53A2378, Revision 1, dated March 10, 1994; or Boeing Service Bulletin 747–53A2378, Revision 3, dated August 11, 2005. After the effective date of this AD, only Revision 3 may be used. After these actions are accomplished, no further action is required by this paragraph.

(n) If any corrosion is found during the inspection required by paragraph (k) or (l)(2) of this AD, prior to further flight, accomplish either paragraph (n)(1) or (n)(2) of this AD, in accordance with Boeing Service Bulletin 747–53A2378, Revision 1, dated March 10, 1994; or Boeing Service Bulletin 747–53A2378, Revision 3, dated August 11, 2005. After the effective date of this AD, only Revision 3 may be used.

(1) Install a new fitting with new fasteners, and reinstall the threshold assembly with new corrosion-resistant fasteners, in accordance with the service bulletin. After these actions are accomplished, no further action is required by this paragraph; or

(2) Blend out corrosion in accordance with the service bulletin.

(i) If blend out of corrosion is beyond 10 percent of original thickness or any crack is found during accomplishment of the blend out procedures, install a new fitting with new fasteners, and reinstall the threshold assembly with new corrosion-resistant fasteners, in accordance with the service bulletin. After these actions are accomplished, no further action is required by this paragraph.

(ii) If blend out of corrosion does not exceed 10 percent of original material thickness, install the repaired fitting with new fasteners, and reinstall the threshold assembly with new corrosion-resistant fasteners, in accordance with the service bulletin. After these actions are accomplished, no further action is required by this paragraph.

(o) For airplanes equipped with main entry door (MED) 3 (this paragraph does not apply to Model 747SP series airplanes): Prior to the accumulation of 16 years of service since date of manufacture of the airplane, or within 18 months after December 16, 1996, whichever occurs later, perform a detailed inspection to detect cracking and/or corrosion of the girt bar support angles at the left and right MED 3, in accordance with Boeing Service Bulletin 747–53A2378, Revision 1, dated March 10, 1994; or Boeing Service Bulletin 747–53A2378, Revision 3, dated August 11, 2005. After the effective date of this AD, only Revision 3 may be used.

(p) If no cracking or corrosion is found during the inspection required by paragraph (o) of this AD, prior to further flight, accomplish either paragraph (p)(1) or (p)(2) of this AD in accordance with the applicable instructions in Boeing Service Bulletin 747–53A2378, Revision 1, dated March 10, 1994; or Boeing Service Bulletin 747–53A2378, Revision 3, dated August 11, 2005. After the effective date of this AD, only Revision 3 may be used.

(1) Remove the inspected angle and reinstall it with a new coat of primer and new fasteners; and reinstall the threshold assembly with new corrosion-resistant fasteners; in accordance with the service bulletin. After these actions are accomplished, no further action is required by this paragraph; or

(2) Reinstall the corner scuff plate and the threshold apron with corrosion-resistant fasteners, in accordance with the service bulletin. Thereafter, repeat the inspection required by paragraph (o) of this AD at intervals not to exceed 6 years.

(q) If any crack common to the support angles is found during the inspection required by paragraph (o) or (p)(2) of this AD, prior to further flight, accomplish the actions specified in paragraph (q)(1) or (q)(2), as applicable, in accordance with Boeing Service Bulletin 747–53A2378, Revision 1, dated March 10, 1994; or Boeing Service Bulletin 747–53A2378, Revision 3, dated August 11, 2005. After the effective date of this AD, only Revision 3 may be used:

(1) Install the new angles with new fasteners, and reinstall the threshold assembly with new corrosion-resistant fasteners. After these actions are accomplished, no further action is required by this paragraph of this AD; or

(2) For any cracking found only in the corner casting as specified in the service bulletin, accomplish either paragraph (q)(2)(i) or (q)(2)(ii) prior to further flight:

(i) Replace the corner casting in accordance with the service bulletin; or

(ii) Repair the cracked part in accordance with a method approved by the Manager, Seattle Aircraft Certification Office (ACO), FAA, Transport Airplane Directorate. Refer to paragraph (w) of this AD for the appropriate procedure for seeking such an approval. (This option is provided in order to give operators time to obtain a replacement corner casing without grounding an airplane.) This repair is considered temporary action only; replacement of the corner casting eventually must be accomplished in accordance with a schedule prescribed by the Manager, Seattle ACO.

(r) If any corrosion is found during the inspection required by paragraph (o) of this AD, prior to further flight, accomplish either paragraph (r)(1) or (r)(2) of this AD, in accordance with Boeing Service Bulletin 747–53A2378, Revision 1, dated March 10, 1994; or Boeing Service Bulletin 747–53A2378, Revision 3, dated August 11, 2005. After the effective date of this AD, only Revision 3 may be used.

(1) Install the new angles with new fasteners, and reinstall the threshold assembly with new corrosion-resistant fasteners, in accordance with the service bulletin. After these actions are accomplished, no further action is required by this paragraph; or

(2) Blend out corrosion in accordance with the service bulletin.

(i) If blend out of corrosion is beyond 10 percent of original thickness, or if any crack common to the support angles is found during accomplishment of the blend out procedures, install the new angles with new fasteners, and reinstall the threshold assembly with new corrosion-resistant fasteners, in accordance with the service bulletin. After these actions are accomplished, no further action is required by this paragraph.

(ii) If blend out of corrosion does not exceed 10 percent of original material thickness, install the repaired angles with new fasteners, and reinstall the threshold assembly with new corrosion-resistant fasteners, in accordance with the service bulletin. After these actions are accomplished, no further action is required by this paragraph.

Actions Accomplished According to Previous Issue of Service Bulletin

(s) Installation of a girt bar support fitting in accordance with Boeing Service Bulletin 747–25A2831, dated August 29, 1991, before the effective date of this AD, is considered acceptable for compliance with the corresponding requirements of paragraphs (h), (i), (j), (l), (m), and (n) of this AD for each affected fitting location.

New Requirements of This AD

Inspections for the Washers and Related Investigative/Corrective Actions

(t) For Groups 7, 8, and 9 airplanes identified in Boeing Service Bulletin 747–53A2378, Revision 3, dated August 11, 2005, on which the support fitting was replaced or repaired in accordance with Boeing Service Bulletin 747–53A2378, dated June 24, 1993; Revision 1, dated March 10, 1994; or Revision 2, dated July 24, 2003; or Boeing Service Bulletin 747–25A2831, dated August 29, 1991: Within 18 months after the effective date of this AD, do a general visual inspection for correct installation of square and conical washers in the girt bar floor fittings, and, before further flight, do all applicable related investigative and corrective actions. Do all actions in accordance with Figure 18 and the applicable steps specified on page 52 of the Accomplishment Instructions of Boeing Service Bulletin 747–53A2378, Revision 3, dated August 11, 2005, except as provided by paragraph (v) of this AD.

(u) For Groups 1 through 6 airplanes identified in Boeing Service Bulletin 747–53A2378, Revision 3, dated August 11, 2005, on which the support fitting was replaced or repaired in accordance with Boeing Service Bulletin 747–53A2378, dated June 24, 1993; Revision 1, dated March 10, 1994; or Revision 2, dated July 24, 2003; or with Boeing Service Bulletin 747–25A2831, dated August 29, 1991: Within 18 months after the effective date of this AD, do a general visual inspection to determine if square and conical washers are installed in the girt bar floor fittings, and before further flight, do all applicable related investigative and corrective actions. Do all actions in accordance with Figure 18 and the applicable steps specified on pages 52 and 53 of the Accomplishment Instructions of Boeing Service Bulletin 747–53A2378, Revision 3, dated August 11, 2005, except as provided by paragraph (v) of this AD.

(v) If any damage is found during any inspection required by paragraphs (t) and (u) of this AD, and the bulletin specifies contacting Boeing for appropriate action: Before further flight, do the repair using a method approved by the Manager, Seattle ACO, FAA, or in accordance with data meeting the certification basis of the airplane approved by an Authorized Representative for the Boeing Commercial Airplanes Delegation Option Authorization who has been authorized by the Manager, Seattle ACO, to make those findings. For a repair method to be approved, the repair must meet the certification basis of the airplane, and the approval must specifically refer to this AD.

Alternative Methods of Compliance (AMOCs)

(w)(1) The Manager, Seattle ACO, FAA, has the authority to approve AMOCs for this AD, if requested in accordance with the procedures found in 14 CFR 39.19.

(2) Before using any AMOC approved in accordance with § 39.19 on any airplane to which the AMOC applies, notify the appropriate principal inspector in the FAA Flight Standards Certificate Holding District Office.

(3) AMOCs approved previously in accordance with AD 96–23–05, are approved as AMOCs for the corresponding provisions of this AD.

Issued in Renton, Washington, on March 7, 2007.

Ali Bahrami,

Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. E7–4738 Filed 3–14–07; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF DEFENSE

Department of the Army

32 CFR Part 635

[Docket No. USA–2007–0007]

RIN 0702–AA56

Law Enforcement Reporting

AGENCY: Department of the Army, DoD.

ACTION: Proposed rule; request for comments.

SUMMARY: The Department of the Army proposes to amend its regulation concerning law enforcement reporting. The regulation prescribes policies and procedures on preparing, reporting, using, retaining, and disposing of Military Police Reports. The regulation prescribes policies and procedures for offense reporting and the release of law enforcement information.

DATES: Consideration will be given to all comments received by April 16, 2007.

ADDRESSES: You may submit comments, identified by 32 CFR Part 635, Docket No. USA–2007–0007 and/or RIN 0702–AA56, by any of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov*. Follow the instructions for submitting comments.
- *Mail:* Federal Docket Management System Office, 1160 Defense Pentagon, Washington, DC 20301–1160.

Instructions: All submissions received must include the agency name and docket number or Regulatory Information Number (RIN) for this **Federal Register** document. The general policy for comments and other submissions from members of the public is to make these submissions available for public viewing on the Internet at *http://www.regulations.gov* as they are received without change, including any personal identifiers or contact information.

FOR FURTHER INFORMATION CONTACT: James Crumley, (703) 692–6721.

SUPPLEMENTARY INFORMATION:

A. Background

In the December 9, 2005 issue of the **Federal Register** (70 FR 73181) the Department of the Army published a proposed rule, amending 32 CFR part

635. The Department of the Army published a proposed rule in the May 15, 2006 issue of the **Federal Register** (71 FR 27961) amending 32 CFR 635 to add the sexual assault reporting procedures. This proposed rule makes numerous administrative changes throughout the document to reflect the changes to the forthcoming update to AR 190–45.

The Administrative Procedure Act, as amended by the Freedom of Information Act requires that certain policies and procedures and other information concerning the Department of the Army be published in the **Federal Register**. The policies and procedures covered by this part fall into that category.

B. Regulatory Flexibility Act

The Department of the Army has determined that the Regulatory Flexibility Act does not apply because the proposed rule does not have a significant economic impact on a substantial number of small entities within the meaning of the Regulatory Flexibility Act, 5 U.S.C. 601–612.

C. Unfunded Mandates Reform Act

The Department of the Army has determined that the Unfunded Mandates Reform Act does not apply because the proposed rule does not include a mandate that may result in estimated costs to State, local or tribal governments in the aggregate, or the private sector, of $100 million or more.

D. National Environmental Policy Act

The Department of the Army has determined that the National Environmental Policy Act does not apply because the proposed rule does not have an adverse impact on the environment.

E. Paperwork Reduction Act

The Department of the Army has determined that the Paperwork Reduction Act does not apply because the proposed rule does not involve collection of information from the public.

F. Executive Order 12630 (Government Actions and Interference With Constitutionally Protected Property Rights)

The Department of the Army has determined that Executive Order 12630 does not apply because the proposed rule does not impair private property rights.

G. Executive Order 12866 (Regulatory Planning and Review)

The Department of the Army has determined that according to the criteria defined in Executive Order 12866 this proposed rule is not a significant regulatory action. As such, the proposed rule is not subject to Office of Management and Budget review under section 6(a)(3) of the Executive Order.

H. Executive Order 13045 (Protection of Children From Environmental Health Risk and Safety Risks)

The Department of the Army has determined that according to the criteria defined in Executive Order 13045 this proposed rule does not apply.

I. Executive Order 13132 (Federalism)

The Department of the Army has determined that according to the criteria defined in Executive Order 13132 this proposed rule does not apply because it will not have a substantial effect on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.

Frederick W. Bucher,

Chief, Law Enforcement Policy and Oversight Branch.

List of Subjects in 32 CFR Part 635

Crime, Law, Law enforcement, Law enforcement officers, Military law.

For reasons stated in the preamble the Department of the Army proposes to revise 32 CFR part 635 to read as follows:

PART 635—LAW ENFORCEMENT REPORTING

Subpart A—Records Administration

Sec.

Subpart B—Release of Information

Subpart C—Offense Reporting

Subpart D—Army Quarterly Trends and Analysis Report

Subpart E—Victim and Witness Assistance Procedures

Authority: 28 U.S.C. 534 note, 42 U.S.C. 10601, 18 U.S.C. 922, 42 U.S.C. 14071, 10 U.S.C. 1562, 10 U.S.C. Chap. 47

Subpart A—Records Administration

§ 635.1 General.

(a) Military police records and files created under provisions of this part will be maintained and disposed of in accordance with instructions and standards prescribed by Army Regulation (AR) 25–400–2, AR 25–55, AR 340–21, and other applicable HQDA directives.

(b) Each Provost Marshal/Director of Emergency Services will appoint in writing two staff members, one primary and one alternate, to account for and safeguard all records containing personal information protected by law. Action will be taken to ensure that protected personal information is used and stored only where facilities and conditions will preclude unauthorized or unintentional disclosure.

(c) Personally identifying information includes, for example, information that is intimate or private to an individual, as distinguished from that which concerns a person's official function or

public life. Specific examples include the social security number (SSN) medical history, home address, and home telephone number.

(d) Access to areas in which military police records are prepared, processed and stored will be restricted to those personnel whose duties require their presence or to other personnel on official business. Military police records containing personal information will be stored in a locked room or locked filing cabinet when not under the personal control of authorized personnel. Alternate storage systems providing equal or greater protection may be used in accordance with AR 25–55.

(e) Only personnel on official business can have access to areas in which computers are used to store, process or retrieve military police records. When processing military police information, computer video display monitors will be positioned so that protected information cannot be viewed by unauthorized persons. Computer output from automated military police systems will be controlled as specified in paragraph (d) of this section.

(f) Output from any locally prepared data or automated systems containing personal information subject to the Privacy Act will be controlled per AR 340–21. All locally created, Army Commands (ACOM), Army Service Component Commands (ASCC) or Direct Reporting Units (DRU) unique automated systems of records containing law enforcement information must be reported to and approved by HQDA, Office of the Provost Marshal General prior to use. The request must clearly document why the COPS MPRS system cannot meet the requirements or objectives of the organization. After review and approval by HQDA, the installation, ACOM, ASCC and DRU will complete and process the systems notice for publication in the **Federal Register** per AR 340–21 and the Privacy Act.

(g) Provost Marshals/Directors of Emergency Services using automated systems will appoint, in writing, an Information Assurance Security Officer (IASO) who will ensure implementation of automation security requirements within the organization. Passwords used to control systems access will be generated, issued, and controlled by the IASO.

(h) Supervisors at all levels will ensure that personnel whose duties involve preparation, processing, filing, and release of military police records are knowledgeable of and comply with policies and procedures contained in this part, AR 25–55, AR 340–21, and other applicable HQDA directives. Particular attention will be directed to provisions on the release of information and protection of privacy.

(i) Military police records identifying juveniles as offenders will be clearly marked as juvenile records and will be kept secure from unauthorized access by individuals. Juvenile records may be stored with adult records but clearly designated as juvenile records even after the individual becomes of legal age. In distributing information on juveniles, Provost Marshals/Directors of Emergency Services will ensure that only individuals with a clear reason to know the identity of a juvenile are provided the identifying information on the juvenile. For example, a community commander is authorized to receive pertinent information on juveniles. When a MPR identifying juvenile offenders must be provided to multiple commanders or supervisors, the Provost Marshal/Director of Emergency Services must sanitize each report to withhold juvenile information not pertaining to that commander's area of responsibility.

(j) Military police records in the custody of USACRC will be processed, stored and maintained in accordance with policy established by the Director, USACRC.

§ 635.2 Safeguarding official information.

(a) Military police records are unclassified except when they contain national security information as defined in AR 380–5.

(b) When military police records containing personal information transmitted outside the installation law enforcement community to other departments and agencies within DOD, such records will be marked ''For Official Use Only.'' Records marked ''For Official Use Only'' will be transmitted as prescribed by AR 25–55. Use of an expanded marking is required for certain records transmitted outside DOD per AR 25–55.

(c) Military police records may also be released to Federal, state, local or foreign law enforcement agencies as prescribed by AR 340–21. Expanded markings will be applied to these records.

§ 635.3 Special requirements of the Privacy Act of 1974.

(a) Certain personal information is protected under the Privacy Act and AR 340–21.

(b) Individuals requested to furnish personal information must be advised of the purpose for which the information is collected and the disclosures by which it is routinely used.

(c) Army law enforcement personnel performing official duties often require an individual's SSN for identification purposes. Personal information may be obtained from identification documents without violating an individual's privacy and without providing a Privacy Act Statement. This personal information can be used to complete military police reports and records. The following procedures may be used to obtain SSNs:

(1) Active Army, U.S. Army Reserve (USAR), Army National Guard (ARNG) and retired military personnel are required to produce their Common Access Card, DD Form 2 (Act), DD Form 2 (Res), or DD Form 2 (Ret) (U.S. Armed Forces of the United States General Convention Identification Card), or other government issued identification, as appropriate.

(2) Family members of sponsors may be requested to produce their DD Form 1173 (Uniformed Services Identification and Privilege Card). Information contained thereon (for example, the sponsor's SSN) may be used to verify and complete applicable sections of MPRs and related forms.

(3) DOD civilian personnel may be requested to produce their appropriate service identification. DA Form 1602 (Civilian Identification) may be requested from DA civilian employees. If unable to produce such identification, DOD civilians may be requested to provide other verifying documentation.

(4) Non-DOD civilians, including family members and those whose status is unknown, will be advised of the provisions of the Privacy Act Statement when requested to disclose their SSN.

(d) Requests for new systems of military police records, changes to existing systems, and continuation systems, not addressed in existing public notices will be processed as prescribed in AR 340–21, after approval is granted by HQDA, OPMG (DAPM–MPD–LE).

§ 635.4 Administration of expelled or barred persons file.

(a) When action is completed by an installation commander to bar an individual from the installation under 18 U.S.C. 1382 the installation Provost Marshal/Director of Emergency Services will be provided

(1) A copy of the letter or order barring the individual.

(2) Reasons for the bar.

(3) Effective date of the bar and period covered.

(b) The Provost Marshal/Director of Emergency Services will maintain a list of barred or expelled persons. When the bar or expulsion action is predicated on

information contained in military police investigative records, the bar or expulsion document will reference the appropriate military police record or MPR. When a MPR results in the issuance of a bar letter the Provost Marshal/Director of Emergency Services will forward a copy of the bar letter to Director, USACRC to be filed with the original MPR. The record of the bar will also be entered into COPS, in the Military Police Reporting System module, under Barrings.

§ 635.5 Police intelligence/criminal information.

(a) The purpose of gathering police intelligence is to identify individuals or groups of individuals in an effort to anticipate, prevent, or monitor possible criminal activity. If police intelligence is developed to the point where it factually establishes a criminal offense, an investigation by the military police, U.S. Army Criminal Investigation Command (USACIDC) or other investigative agency will be initiated. The crimes in § 635.5(b)(2) and (3) will be reported to the nearest Army counterintelligence office as required by AR 381–12.

(b) Information on persons and organizations not affiliated with DOD may not normally be acquired, reported, processed or stored. Situations justifying acquisition of this information include, but are not limited to—

(1) Theft, destruction, or sabotage of weapons, ammunition, equipment facilities, or records belonging to DOD units or installations.

(2) Possible compromise of classified defense information by unauthorized disclosure or espionage.

(3) Subversion of loyalty, discipline, or morale of DA military or civilian personnel by actively encouraging violation of laws, disobedience of lawful orders and regulations, or disruption of military activities.

(4) Protection of Army installations and activities from potential threat.

(5) Information received from the FBI, state, local, or international law enforcement agencies which directly pertain to the law enforcement mission and activity of the installation Provost Marshal Office/Directorate of Emergency Services, ACOM, ASCC or DRU Provost Marshal Office Directorate of Emergency Services, or that has a clearly identifiable military purpose and connection. A determination that specific information may not be collected, retained or disseminated by intelligence activities does not indicate that the information is automatically eligible for collection, retention, or dissemination under the provisions of this part. The policies in this section are not intended and will not be used to circumvent any federal law that restricts gathering, retaining or dissemination of information on private individuals or organizations.

(c) Retention and disposition of information on non-DOD affiliated individuals and organizations are subject to the provisions of AR 380–13 and AR 25–400–2.

(d) Police intelligence such as TALON events will be captured by utilizing the TALON report format. These reports will be identified as ''Pre-TALON'' reports. The Provost Marshal Office/Directorate of Emergency Services will forward these reports to the counterintelligence activity which supports their installation/area. The counterintelligence activity will determine if the suspicious incident/activity should be entered into the DoD TALON reporting system. The counterintelligence activity will inform the submitting Army law enforcement agency as to whether or not the ''Pre-Talon'' report was submitted into the DoD TALON reporting system.

(e) In addition to Pre-TALON reporting, Installation Law Enforcement Agencies/Activities will also comply with their Combatant Command's policies regarding the reporting of suspicious activities or events which meet established criteria.

(f) If a written extract from local police intelligence files is provided to an authorized investigative agency, the following will be included on the transmittal documents: ''THIS DOCUMENT IS PROVIDED FOR INFORMATION AND USE. COPIES OF THIS DOCUMENT, ENCLOSURES THERETO, AND INFORMATION THEREFROM, WILL NOT BE FURTHER RELEASED WITHOUT THE PRIOR APPROVAL OF THE INSTALLATION PROVOST MARSHAL/DIRECTOR OF EMERGENCY SERVICES.''

(g) Local police intelligence files may be exempt from certain disclosure requirements by AR 25–55 and the Freedom of Information Act (FOIA).

§ 635.6 Name checks.

(a) Information contained in military police records may be released under the provisions of AR 340–21 to authorized personnel for valid background check purposes. Examples include child care/youth program providers, access control, unique or special duty assignments, and security clearance procedures. Any information released must be restricted to that necessary and relevant to the requester's official purpose. Provost Marshals/Directors of Emergency Services will establish written procedures to ensure that release is accomplished in accordance with AR 340–21.

(b) Checks will be accomplished by a review of the COPS MPRS. Information will be disseminated according to Subpart B of this part.

(c) In response to a request for local files or name checks, Provost Marshals/Directors of Emergency Services will release only founded offenses with final disposition. Offenses determined to be unfounded will not be released. These limitations do not apply to requests submitted by law enforcement agencies for law enforcement purposes, and counterintelligence investigative agencies for counterintelligence purposes.

(d) COPS MPRS is a database, which will contain all military police reports filed worldwide. Authorized users of COPS MPRS can conduct name checks for criminal justice purposes. To conduct a name check, users must have either the social security number/foreign national number, or the first and last name of the individual. If a search is done by name only, COPS MPRS will return a list of all matches to the data entered. Select the appropriate name from the list.

(e) A successful query of COPS MPRS would return the following information:

(1) Military Police Report Number;

(2) Report Date;

(3) Social Security Number;

(4) Last Name;

(5) First Name;

(6) Protected Identity (Y/N);

(7) A link to view the military police report; and

(8) Whether the individual is a subject, victim, or a person related to the report disposition.

(f) Name checks will include the criteria established in COPS MPRS and the USACRC. All of the policies and procedures for such checks will conform to the provisions of this part. Any exceptions to this policy must be coordinated with HQDA, Office of the Provost Marshal General before any name checks are conducted. The following are examples of appropriate uses of the name check feature of COPS MPRS:

(1) Individuals named as the subjects of serious incident reports.

(2) Individuals named as subjects of investigations who must be reported to the USACRC.

(3) Employment as child care/youth program providers.

(4) Local checks of the COPS MPRS as part of placing an individual in the COPS MPRS system.

(5) Name checks for individuals employed in law enforcement positions.

(g) Provost Marshals/Directors of Emergency Services will ensure that an audit trail is established and maintained for all information released from military police records.

(h) Procedures for conduct of name checks with the USACRC are addressed in AR 195–2. The following information is required for USACRC name checks (when only the name is available, USACRC should be contacted telephonically for assistance):

(1) Full name, date of birth, SSN, and former service number of the individual concerned.

(2) The specific statute, directive, or regulation on which the request is based, when requested for other than criminal investigative purposes.

(i) Third party checks (first party asks second party to obtain information from third party on behalf of first party) will not be conducted.

§ 635.7 Registration of sex offenders.

Soldiers who are convicted by court-martial for certain sexual offenses must comply with all applicable state registration requirements in effect in the state in which they reside. See AR 190–47, Chapter 14 and AR 27–10, Chapter 24. This is a statutory requirement based on the Jacob Wetterling Act, and implemented by DOD Instruction 1325.7, and AR 27–10. Provost Marshals/Directors of Emergency Services should coordinate with their local Staff Judge Advocate to determine if an individual must register. The registration process will be completed utilizing the state registration form, which is available through state and local law enforcement agencies. A copy of the completed registration form will be maintained in the installation Provost Marshal Office/Directorate of Emergency Services. Additionally, a Military Police Report (DA Form 3975) will be completed as an information entry into COPS. Installation Provost Marshals/Directors of Emergency Services will provide written notice to state and local law enforcement agencies of the arrival of an offender to the local area so the registration process can be completed.

Subpart B—Release of Information

§ 635.8 General.

(a) The policy of HQDA is to conduct activities in an open manner and provide the public accurate and timely information. Accordingly, law enforcement information will be released to the degree permitted by law and Army regulations.

(b) Any release of military police records or information compiled for law enforcement purposes, whether to persons within or outside the Army, must be in accordance with the FOIA and Privacy Act.

(c) Requests by individuals for access to military police records about themselves will be processed in compliance with AR 25–55 and AR 340–21.

(d) Military police records in the temporary possession of another organization remain the property of the originating law enforcement agency. The following procedures apply to any organization authorized temporary use of military police records:

(1) Any request from an individual seeking access to military police records will be immediately referred to the originating law enforcement agency for processing.

(2) When the temporary purpose of the using organization has been satisfied, the military police records will be destroyed or returned to the originating law enforcement agency.

(3) A using organization may maintain information from military police records in their system of records, if approval is obtained from the originating law enforcement agency. This information may include reference to a military police record (for example, MPR number or date of offense), a summary of information contained in the record, or the entire military police record. When a user includes a military police record in its system of records, the originating law enforcement agency may delete portions from that record to protect special investigative techniques, maintain confidentiality, preclude compromise of an investigation, and protect other law enforcement interests.

§ 635.9 Guidelines for disclosure within DOD.

(a) Criminal record information contained in military police documents will not be disseminated unless there is a clearly demonstrated official need to know. A demonstrated official need to know exists when the record is necessary to accomplish a function that is within the responsibility of the requesting activity or individual, is prescribed by statute, DOD directive, regulation, or instruction, or by Army regulation.

(1) Criminal record information may be disclosed to commanders or staff agencies to assist in executing criminal justice functions. Only that information reasonably required will be released. Such disclosure must clearly relate to a law enforcement function.

(2) Criminal record information related to subjects of criminal justice disposition will be released when required for security clearance procedures.

(3) Criminal record information may be released to an activity when matters of national security are involved.

(4) When an individual informs an activity of criminal record information pertaining to them, the receiving activity may seek verification of this information through the responsible law enforcement agency or may forward the request to that organization. The individual must be advised by the receiving agency of the action being pursued. Law enforcement agencies will respond to such requests in the same manner as FOIA and Privacy Act cases.

(b) Nothing in this part will be construed to limit the dissemination of information between military police, the USACIDC, and other law enforcement agencies within the Army and DOD.

§ 635.10 Release of information.

(a) Release of information from Army records to agencies outside DOD will be governed by AR 25–55, AR 340–21, AR 600–37, and this part. Procedures for release of certain other records and information is contained in AR 20–1, AR 27–20, AR 27–40, AR 40–66, AR 195–2, AR 360–1, and AR 600–85. Installation drug and alcohol offices may be provided an extract of DA Form 3997 (Military Police Desk Blotter) for offenses involving the use of alcohol or drugs (for example, drunk driving, drunk and disorderly conduct, or positive urinalysis) or illegal use of drugs.

(b) Installation Provost Marshals/ Directors of Emergency Services are the release authorities for military police records under their control. They may release criminal record information to other activities as prescribed in AR 25–55 and AR 340–21, and this part.

(c) Authority to deny access to criminal records information rests with the initial denial authority (IDA) for the FOIA and the access and amendment refusal authority (AARA) for Privacy Acts cases, as addressed in AR 25–55 and AR 340–21.

§ 635.11 Release of information under the Freedom of Information Act (FOIA).

(a) The release and denial authorities for all FOIA cases concerning military police records include Provost Marshals/Directors of Emergency Services and the Commander, USACIDC. Authority to act on behalf of the Commander, USACIDC is delegated to the Director, USACRC.

(b) FOIA requests from members of the press will be coordinated with the installation public affairs officer prior to release of records under the control of

the installation Provost Marshal/ Director of Emergency Services. When the record is on file at the USACRC the request must be forwarded to the Director, USACRC.

(c) Requests will be processed as prescribed in AR 25–55 and as follows:

(1) The Provost Marshal/Director of Emergency Services will review requested reports to determine if any portion is exempt from release. Any discretionary decision to disclose information under the FOIA should be made only after full and deliberate consideration of the institutional, commercial, and personal privacy interests that could be implicated by disclosure of the information.

(2) Statutory and policy questions will be coordinated with the local staff judge advocate.

(3) Coordination will be completed with the local USACIDC activity to ensure that the release will not interfere with a criminal investigation in progress or affect final disposition of an investigation.

(4) If it is determined that a portion of the report, or the report in its entirety will not be released, the request to include a copy of the MPR or other military police records will be forwarded to the Director, USACRC, ATTN: CICR–FP, 6010 6th Street, Fort Belvoir, VA 22060–5585. The requestor will be informed that their request has been sent to the Director, USACRC, and provided the mailing address for the USACRC. When forwarding FOIA requests, the outside of the envelope will be clearly marked ''FOIA REQUEST.''

(5) A partial release of information by a Provost Marshal/Director of Emergency Services is permissible when partial information is acceptable to the requester. (An example would be the deletion of a third party's social security number, home address, and telephone number, as permitted by law). If the requester agrees to the omission of exempt information, such cases do not constitute a denial. If the requester insists on the entire report, a copy of the report and the request for release will be forwarded to the Director, USACRC. There is no requirement to coordinate such referrals at the installation level. The request will simply be forwarded to the Director, USACRC for action.

(6) Requests for military police records that have been forwarded to USACRC and are no longer on file at the installation Provost Marshal Office/ Directorate of Emergency Services will be forwarded to the Director, USACRC for processing.

(7) Requests concerning USACIDC reports of investigation or USACIDC files will be referred to the Director, USACRC. In each instance, the requestor will be informed of the referral and provided the Director, USACRC address.

(8) Requests concerning records that are under the supervision of an Army activity, or other DOD agency, will be referred to the appropriate agency for response.

§ 635.12 Release of information under the Privacy Act of 1974.

(a) Military police records may be released according to provisions of the Privacy Act of 1974, as implemented by AR 340–21 and this part.

(b) The release and denial authorities for all Privacy Act cases concerning military police records are provided in § 635.10 of this part.

(c) Privacy Act requests for access to a record, when the requester is the subject of that record, will be processed as prescribed in AR 340–21.

§ 635.13 Amendment of records.

(a) *Policy.* An amendment of records is appropriate when such records are established as being inaccurate, irrelevant, untimely, or incomplete. Amendment procedures are not intended to permit challenging an event that actually occurred. For example, a request to remove an individual's name as the subject of a MPR would be proper providing credible evidence was presented to substantiate that a criminal offense was not committed or did not occur as reported. Expungement of a subject's name from a record because the commander took no action or the prosecutor elected not to prosecute normally will not be approved. In compliance with DOD policy, an individual will still remain entered in the Defense Clearance Investigations Index (DCII) to track all reports of investigation.

(b) *Procedures.* (1) Installation Provost Marshals/Directors of Emergency Services will review amendment requests. Upon receipt of a request for an amendment of a military police record that is 5 or less years old, the installation Provost Marshal/Director of Emergency Services will gather all relevant available records at their location. The installation Provost Marshal/Director of Emergency Services will review the request and either approve the request or forward it to the Director, USACRC with recommendation and rationale for denial. In accordance with AR 340–21, paragraph 1–71, the Commanding General, USACIDC is the sole access and amendment authority for criminal investigation reports and military police reports. Access and amendment refusal authority is not delegable. If the decision is made to amend a MPR, a supplemental DA Form 3975 will be prepared. The supplemental DA Form 3975 will change information on the original DA Form 3975 and will be mailed to the Director, USACRC with the amendment request from the requestor as an enclosure. The Director, USACRC will file the supplemental DA Form 3975 with the original MPR and notify the requestor of the amendment of the MPR.

(2) Requests to amend military police documents that are older than 5 years will be coordinated through the Director, USACRC. The installation Provost Marshal/Director of Emergency Services will provide the Director, USACRC a copy of an individual's request to amend a military police record on file at the USACRC. If the Director, USACRC receives an amendment request, the correspondence with any documentation on file at the USACRC will be sent to the originating Provost Marshal Office/Directorate of Emergency Services. The installation Provost Marshal/Director of Emergency Services will review the request and either approve the request or forward it to the Director, USACRC for denial. A copy of the Provost Marshal/Director of Emergency Services' decision must be sent to the Director, USACRC to be filed in the USACRC record. If an amendment request is granted, copies of the supplemental DA Form 3975 will be provided to each organization, activity, or individual who received a copy of the original DA Form 3975.

(3) If the Provost Marshal Office/ Directorate of Emergency Services no longer exists, the request will be staffed with the ACOM, ASCC or DRU Provost Marshal/Director of Emergency Services office that had oversight responsibility for the Provost Marshal Office/ Directorate of Emergency Services at the time the DA Form 3975 was originated.

§ 635.14 Accounting for military police record disclosure.

(a) AR 340–21 prescribes accounting policies and procedures concerning the disclosure of military police records.

(b) Provost Marshals/Directors of Emergency Services will develop local procedures to ensure that disclosure data requirements by AR 340–21 are available on request.

§ 635.15 Release of law enforcement information furnished by foreign governments or international organizations.

(a) Information furnished by foreign governments or international organizations is subject to disclosure,

unless exempted by AR 25–55, AR 340–21, federal statutes or executive orders.

(b) Information may be received from a foreign source under an express pledge of confidentiality as described in AR 25–55 and AR 340–21 (or under an implied pledge of confidentiality given prior to September 27, 1975).

(1) Foreign sources will be advised of the provisions of the Privacy Act of 1974, the FOIA, and the general and specific law enforcement exemptions available, as outlined in AR 340–21 and AR 25–55.

(2) Information received under an express promise of confidentiality will be annotated in the MPR or other applicable record.

(3) Information obtained under terms of confidentiality must clearly aid in furthering a criminal investigation.

(c) Denial recommendations concerning information obtained under a pledge of confidentiality, like other denial recommendations, will be forwarded by the records custodian to the appropriate IDA or AARA per AR 25–55 or AR 340–21.

(d) Release of U.S. information (classified military information or controlled unclassified information) to foreign governments is accomplished per AR 380–10.

Subpart C—Offense Reporting

§ 635.16 General.

(a) This subpart establishes policy for reporting founded criminal offenses by Installation Management Command (IMCOM), Army Materiel Command (AMC) and Medical Command (MEDCOM) installation and ACOM, ASCC and DRU Provost Marshal Offices/Directorates of Emergency Services.

(b) This subpart prescribes reporting procedures, which require the use of the COPS MPRS and a systems administrator to ensure that the system is properly functioning. Reporting requirements include—

(1) Reporting individual offenders to the USACRC, NCIC, CJIS, and the DOD.

(2) *Crime reports to the DOD.* DOD collects data from all the Services utilizing the Defense Incident-Based Reporting System (DIBRS). The Army inputs its data into DIBRS utilizing COPS. Any data reported to DIBRS is only as good as the data reported into COPS, so the need for accuracy in reporting incidents and utilizing proper offense codes is great. DIBRS data from DOD is eventually sent to the Department of Justice's National Incident-Based Reporting System (NIBRS). The data is eventually incorporated into the Uniform Crime Report.

(c) A Provost Marshal Office/Directorate of Emergency Services initiating a DA Form 3975 or other military police investigation has reporting responsibility explained throughout this subpart and this part in general.

(d) In the event the Provost Marshal Office/Directorate of Emergency Services determines that their office does not have investigative responsibility or authority, the MPR will be terminated and the case cleared by exceptional clearance. A case cleared by exceptional clearance is closed by the Provost Marshal/Director of Emergency Services when no additional investigative activity will be performed or the case is referred to another agency. If a case is transferred to the Provost Marshal/Director of Emergency Services from another law enforcement investigation agency the Provost Marshal Office/Directorate of Emergency Services will have all reporting responsibility using the COPS MPRS system.

§ 635.17 Military Police Report.

(a) *General use.* DA form 3975 is a multipurpose form used to—

(1) Record all information or complaints received or observed by military police.

(2) Serve as a record of all military police and military police investigator activity.

(3) Document entries made into the COPS MPRS system and other automated systems.

(4) Report information concerning investigations conducted by civilian law enforcement agencies related to matters of concern to the U.S. Army.

(5) Advise commanders and supervisors of offenses and incidents involving personnel or property associated with their command or functional responsibility.

(6) Report information developed by commanders investigating incidents or conducting inspections that result in the disclosure of evidence that a criminal offense has been committed.

(b) *Special use.* The DA Form 3975 will be used to—

(1) Transmit completed DA Form 3946 (Military Police Traffic Accident Report). This will include statements, sketches, or photographs that are sent to a commander or other authorized official.

(2) Transmit the DD Form 1805 (U.S District Court Violation Notice) when required by local installation or U.S. Magistrate Court policy. The DA Form 3975 is used to advise commanders or supervisors that military, civilian, or contract personnel have been cited on a DD Form 1805.

(3) Match individual subjects with individual victims or witnesses, and founded criminal offenses. This is a federal statutory requirement. This is done using the relationships tab within COPS MPRS.

(4) Document victim/witness liaison activity.

(c) *Distribution.* The DA Form 3975 will be prepared in three copies, signed by the Provost Marshal/Director of Emergency Services or a designated representative, and distributed as follows—

(1) Original to USACRC. Further information, arising or developed at a later time, will be forwarded to USACRC using a supplemental DA Form 3975. Reports submitted to USACRC will include a good, legible copy of all statements, photographs, sketches, laboratory reports, and other information that substantiates the offense or facilitates the understanding of the report. The USACRC control number must be recorded on every DA Form 3975 sent to the USACRC. A report will not be delayed for adjudication or commander's action beyond 45 days.

(2) One copy retained in the Provost Marshal/Director of Emergency Services' files.

(3) One copy forwarded through the field grade commander to the immediate commander of each subject or organization involved in an offense.

(d) *Changing reports for unfounded offenses.* If an offense is determined to be unfounded, after the case has been forwarded to USACRC, the following actions will be completed:

(1) A supplemental DA Form 3975, using the same MPR number and USACRC control number will be submitted stating the facts of the subsequent investigation and that the case is unfounded.

(2) A copy of the supplemental DA Form 3975 will be provided to those agencies or activities that received a copy of the completed DA Form 3975 at the time of submission to USACRC and to the commander for action.

§ 635.18 Identifying criminal incidents and subjects of investigation.

(a) An incident will not be reported as a founded offense unless adequately substantiated by police investigation. A person or entity will be reported as the subject of an offense on DA Form 3975 when credible information exists that the person or entity may have committed a criminal offense. The decision to title a person is an

operational rather than a legal determination. The act of titling and indexing does not, in and of itself, connote any degree of guilt or innocence; but rather, ensures that information in a report of investigation can be retrieved at some future time for law enforcement and security purposes. Judicial or adverse administrative actions will not be based solely on the listing of an individual or legal entity as a subject on DA Form 3975.

(b) A known subject will be reported to the USACRC when the suspected offense is punishable by confinement of six months or more. The COPS MPRS will be used to track all other known subjects. A subject can be a person, corporation, or other legal entity, or organization about which credible information exists that would cause a trained law enforcement officer to presume that the person, corporation, other legal entity or organization may have committed a criminal offense.

(c) When investigative activity identifies a subject, all facts of the case must be considered. When a person, corporation, or other legal entity is entered in the subject block of the DA Form 3975, their identity is recorded in DA automated systems and the DCII. Once entered into the DCII, the record can only be removed in cases of mistaken identity or if an error was made in applying the credible information standard at the time of listing the entity as a subject of the report. It is emphasized that the credible information error must occur at the time of listing the entity as the subject of the MPR rather than subsequent investigation determining that the MPR is unfounded. This policy is consistent with DOD reporting requirements. The Director, USACRC enters individuals from DA Form 3975 into the DCII.

§ 635.19 Offense codes.

(a) The offense code describes, as nearly as possible, the complaint or offense by using an alphanumeric code. Appendix C of AR 190–45 lists the offense codes that are authorized for use within the Army. This list will be amended from time to time based on new reporting requirements mandated by legislation or administrative procedures. ACOM, ASCC, DRU commanders and installation Provost Marshals/Directors of Emergency Services will be notified by special letters of instruction issued in numerical order from HQDA, Office of the Provost Marshal General (DAPM–MPD–LE) when additions or deletions are made to list. The COPS MPRS module will be used for all reporting requirements.

(b) ACOM, ASCC, DRU and installations may establish local offense codes in category 2 (ACOM, ASCC, DRU and installation codes) for any offense not otherwise reportable. Locally established offense codes will not duplicate, or be used as a substitute for any offense for which a code is contained for other reportable incidents. Category 2 incidents are not reported to the Director, USACRC or the DOJ. If an offense occurs meeting the reporting description contained in Appendix C of AR 190–45, that offense code takes precedence over the local offense code. Local offense codes may be included, but explained, in the narrative of the report filed with the USACRC. Use the most descriptive offense code to report offenses.

(c) Whenever local policy requires the Provost Marshal/Director of Emergency Services to list the subject's previous offenses on DA Form 3975, entries will reflect a summary of disposition for each offense, if known.

§ 635.20 Military Police Codes (MPC).

(a) MPCs identify individual Provost Marshal Offices/Directorates of Emergency Services. The Director, USACRC will assign MPCs to Provost Marshal Offices/Directorates of Emergency Services.

(b) Requests for assignment of a MPC will be included in the planning phase of military operations, exercises, or missions when law enforcement operations are anticipated. The request for a MPC will be submitted as soon as circumstances permit, without jeopardizing the military operation to HQDA, Office of the Provost Marshal General (DAPM–MPD–LE). Consistent with security precautions, ACOM, ASCC and DRU will immediately inform HQDA, Office of the Provost Marshal General (DAPM–MPD–LE) when assigned or attached military police units are notified for mobilization, relocation, activation, or inactivation.

(c) When a military police unit is alerted for deployment to a location not in an existing Provost Marshal/Director of Emergency Services' operational area, the receiving ACOM, ASCC, DRU or combatant commander will request assignment of an MPC number from HQDA, Office of the Provost Marshal General (DAPM–MPD–LE) providing the area of operations does not have an existing MPC number. The receiving ACOM, ASCC, DRU or Unified Combatant Commander is further responsible for establishing an operational COPS system for the deployment.

§ 635.21 USACRC control numbers.

(a) Case numbers to support reporting requirements will be assigned directly to each installation via COPS. To ensure accuracy in reporting criminal incidents, USACRC control numbers will be used only one time and in sequence. Every MPR sent to the USACRC will have a USACRC control number reported. Violation of this policy could result in significant difficulties in tracing reports that require corrective action.

(b) If during the calendar year ACOM, ASCC or DRU reassigns control numbers from one installation to another, HQDA, Office of the Provost Marshal General (DAPM–MPD–LE) will be notified. The Director USACRC will receive an information copy of such notification from ACOM, ASCC or DRU's law enforcement operations office.

(c) USACRC control numbers will be issued along with each newly assigned MPC.

(d) When the deploying unit will be located in an area where there is an existing Provost Marshal/Director of Emergency Services activity, the deploying unit will use the MPC number and USACRC control numbers of the host Provost Marshal/Director of Emergency Services.

§ 635.22 Reserve component, U.S. Army Reserve, and Army National Guard personnel.

(a) When in a military duty status pursuant to official orders (Federal status for National Guard) Reserve and National Guard personnel will be reported as active duty. Otherwise they will be reported as civilians.

(b) The DA Form 3975 and DA Form 4833 will be forwarded directly to the appropriate Regional Readiness Command or the Soldier's division commander. A copy of the DA Form 3975 will also be forwarded to Chief, Army Reserve/Commander, United States Army Reserve Command, AFRC–JAM, 1404 Deshler Street, Fort McPherson, GA 30330. The forwarding correspondence will reflect this regulation as the authority to request disposition of the individual.

§ 635.23 DA Form 4833 (Commander's Report of Disciplinary or Administrative Action).

(a) *Use.* DA Form 4833 is used with DA Form 3975 to—

(1) Record actions taken against identified offenders.

(2) Report the disposition of offenses investigated by civilian law enforcement agencies.

(b) *Preparation by the Provost Marshal/Director of Emergency Services.*

The installation Provost Marshal/Director of Emergency Services initiates this critical document and is responsible for its distribution and establishing a suspense system to ensure timely response by commanders. Disposition reports are part of the reporting requirements within DA, DOD, and DOJ.

(c) *Completion by the unit commander.* Company, troop, and battery level commanders are responsible and accountable for completing DA Form 4833 with supporting documentation in all cases investigated by MPI, civilian detectives employed by the Department of the Army, and the PMO. The Battalion Commander or the first Lieutenant Colonel in the chain of command is responsible and accountable for completing DA Form 4833 with support documentation (copies of Article 15s, court-martial orders, reprimands, etc.) for all USACIDC investigations. The commander will complete the DA Form 4833 within 45 days of receipt.

(1) Appropriate blocks will be checked and blanks annotated to indicate the following:

(i) Action taken (for example, judicial, nonjudicial, or administrative). In the event the commander takes action against the soldier for an offense other than the one listed on the DA Form 3975, the revised charge or offense will be specified in the REMARKS section of the DA Form 4833.

(ii) Sentence, punishment, or administrative action imposed.

(iii) Should the commander take no action, the DA Form 4833 must be annotated to reflect that fact.

(2) If the commander cannot complete the DA Form 4833 within 45 days, a written memorandum is required to explain the circumstances. The delay will have an impact on other reporting requirements (*e.g.*, submitting fingerprint cards to the FBI).

(d) *Procedures when subjects are reassigned.* When the subject of an offense is reassigned, the Provost Marshal/Director of Emergency Services will forward the DA Form 3975, DA Form 4833, and all pertinent attachments to the gaining installation Provost Marshal/Director of Emergency Services who must ensure that the new commander completes the document. Copies of the documents may be made and retained by the processing Provost Marshal Office/Directorate of Emergency Services before returning the documents to the losing installation Provost Marshal/Director of Emergency Services for completion of automated entries and required reports.

(e) *Report on subjects assigned to other installations.* When the DA Form 3975 involves a subject who is assigned to another installation, the initiating Provost Marshal/Director of Emergency Services will forward the original and two copies of DA Form 4833 to the Provost Marshal/Director of Emergency Services of the installation where the soldier is permanently assigned. The procedures in paragraph (d) of this section will be followed for soldiers assigned to other commands.

(f) *Offenses not reportable to USACRC.* When the offense is not within a category reportable to USACRC, the original DA Form 4833 is retained by the Provost Marshal/Director of Emergency Services. Otherwise, the original is sent to the Director, USACRC for filing with the MPR.

(g) *Civilian court proceedings.* If a soldier is tried in a civilian court, and the Provost Marshal/Director of Emergency Services has initiated a MPR, the Provost Marshal/Director of Emergency Services must track the civilian trial and report the disposition on DA Form 4833 as appropriate. That portion of the signature block of DA Form 4833 that contains the word ‘‘Commanding’’ will be deleted and the word ‘‘Reporting’’ substituted. The Provost Marshal/Director of Emergency Services or other designated person will sign DA Form 4833 before forwarding it to USACRC.

(h) *Dissemination to other agencies.* A copy of the completed DA Form 4833 reflecting offender disposition will also be provided to those agencies or offices that originally received a copy of DA Form 3975 when evidence is involved. The evidence custodian will also be informed of the disposition of the case. Action may then be initiated for final disposition of evidence retained for the case now completed.

(i) *Review of offender disposition by the Provost Marshal/Director of Emergency Services.* On receipt of DA Form 4833 reflecting no action taken, the Provost Marshal/Director of Emergency Services will review the MPR. The review will include, but is not limited to the following—

(1) Determination of the adequacy of supporting documentation.

(2) Whether or not coordination with the supporting Staff Judge Advocate should have been sought prior to dispatch of the report to the commander for action.

(3) Identification of functions that warrant additional training of military police or security personnel (for example, search and seizure, evidence handling, or rights warning).

(j) *Offender disposition summary reports.* Provost Marshals/Directors of Emergency Services will provide the supported commander (normally, the general courts-martial convening authority or other persons designated by such authority) summary data of offender disposition as required or appropriate. Offender disposition summary data will reflect identified offenders on whom final disposition has been reported. These data will be provided in the format and at the frequency specified by the supported commander.

§ 635.24 Updating the COPS MPRS.

Installation Provost Marshals/Directors of Emergency Services will establish standard operating procedures to ensure that every founded offense is reported into the COPS MPRS. Timely and accurate reporting is critical. If a case remains open, changes will be made as appropriate. This includes reporting additional witnesses and all aspects of the criminal report.

§ 635.25 Submission of criminal history data to the CJIS.

(a) *General.* This paragraph establishes procedures for submitting criminal history data (fingerprint cards) to CJIS when the Provost Marshal/Director of Emergency Services has completed a criminal inquiry or investigation. The policy only applies to members of the Armed Forces and will be followed when a military member has been read charges and the commander initiates proceedings for—

(1) *Field Grade Article 15, Uniform Code of Military Justice.* Initiation refers to a commander completing action to impose non-judicial punishment. Final disposition shall be action on appeal by the next superior authority, expiration of the time limit to file an appeal, or the date the military member indicates that an appeal will not be submitted.

(2) *A special or general courts-martial.* Initiation refers to the referral of court-martial charges to a specified court by the convening authority or receipt by the commander of an accused soldier's request for discharge in lieu of court-martial. Final disposition of military judicial proceedings shall be action by the convening authority on the findings and sentence, or final approval of a discharge in lieu of court-martial. The procedures in this subpart meet administrative and technical requirements for submitting fingerprint cards and criminal history information to CJIS. No variances are authorized. Results of summary court-martial will not be reported to the FBI.

(3) *DA Form 4833.* In instances where final action is taken by a magistrate, the Provost Marshal/Director of Emergency Services will complete the DA Form 4833.

(4) *Fingerprint cards.* Provost Marshal Offices/Directorates of Emergency Services will submit fingerprint cards on subjects apprehended as a result of Drug Suppression Team investigations and operations unless the USACIDC is completing the investigative activity for a felony offense. In those cases, the USACIDC will complete the fingerprint report process.

(b) *Procedures.* The following procedures must be followed when submitting criminal history data to CJIS.

(1) Standard FBI fingerprint cards will be used to submit criminal history data to CJIS. FBI Form FD 249, (Suspect Fingerprint Card) will be used when a military member is a suspect or placed under apprehension for an offense listed in Appendix D of AR 190–45. Two FD 249s will be completed. One will be retained in the Provost Marshal/Director of Emergency Services file. The second will be sent to the Director, USACRC and processed with the MPR as prescribed in this subpart. A third set of prints will also be taken on the FBI Department of Justice (DOJ) Form R–84 (Final Disposition Report). The R–84 requires completion of the disposition portion and entering of the offenses on which the commander took action. Installation Provost Marshals/Directors of Emergency Services are authorized to requisition the fingerprint cards by writing to FBI, J. Edgar Hoover Building, Personnel Division, Printing Unit, Room lB973, 925 Pennsylvania Ave., NW., Washington, DC 20535–0001.

(2) Fingerprint cards will be submitted with the MPR to the Director, USACRC, ATTN: CICR–CR, 6010 6th Street, Fort Belvoir, VA 22060–5585 only when the commander has initiated judicial or nonjudicial action amounting to a Field Grade Article 15 or greater. The Director, CRC will forward the fingerprint card to CJIS. The USACRC is used as the central repository for criminal history information in the Army. They also respond to inquiries from CJIS, local, state and other federal law enforcement agencies.

(3) Submission of the MPR with the FD 249 to USACRC will normally occur upon a commander's initiation of judicial or nonjudicial proceedings against a military member. If final disposition of the proceeding is anticipated within 60 days of command initiation of judicial or nonjudicial proceedings, the FD 249 may be held and final disposition recorded on FD 249. Provost Marshals/Directors of Emergency Services and commanders must make every effort to comply with the 60 days reporting requirement to ensure that the FD Form 249 is used as the primary document to submit criminal history to CJIS. Approval of a discharge in lieu of court-martial will be recorded as a final disposition showing the nature and character of the discharge in unabbreviated English (e.g., resignation in lieu of court-martial; other than honorable discharge) and will also be forwarded to USACRC.

(4) If the commander provides the DA Form 4833 after the 60th day, a letter of transmittal will be prepared by the Provost Marshal/Director of Emergency Services forwarding the FBI (DOJ) R–84 with the DA Form 4833 to the USACRC within 5 days after disposition. Submission of fingerprint cards shall not be delayed pending appellate actions. Dispositions that are exculpatory (e.g., dismissal of charges, acquittal) shall also be filed.

(5) The procedures for submitting fingerprint cards will remain in effect until automated systems are in place for submission of fingerprints electronically.

§ 635.26 Procedures for reporting absence without leave (AWOL) and desertion offenses.

(a) *AWOL reporting procedures.* (1) The commander will notify the installation Provost Marshal/Director of Emergency Services in writing within 24 hours after a soldier has been reported AWOL.

(2) The Provost Marshal/Director of Emergency Services will initiate an information blotter entry.

(3) If the AWOL soldier surrenders to the parent unit or returns to military control at another installation, the provisions of AR 630–10 will be followed.

(4) On receipt of written notification of the AWOL soldier's return or upon apprehension, the Provost Marshal/Director of Emergency Services will initiate a reference blotter entry indicating the soldier's return to military control and will prepare an initial DA Form 3975, reflecting the total period of unauthorized absence, and the DA Form 4833. Both of these documents will be forwarded through the field grade commander to the unit commander.

(5) The unit commander will report action taken on the DA Form 4833 no later than the assigned suspense date or provide a written memorandum to the Provost Marshal/Director of Emergency Services explaining the delay.

(6) An original DD Form 460 (Provisional Pass) is issued to the soldier to facilitate their return to the parent unit. DD Form 460 will not be required if the Provost Marshal/Director of Emergency Services elects to return the soldier through a different means.

(7) If the soldier is apprehended at or returns to an installation other than his or her parent installation DA Form 3975 and 4833 with a copy of DD Form 460 will be sent to the parent installation Provost Marshal/Director of Emergency Services. The parent installation Provost Marshal/Director of Emergency Services will initiate an information blotter entry reflecting the AWOL soldiers return to military control. A DA Form 3975 and 4833 with an appropriate suspense will be sent through the field grade commander to the unit commander. On return of the completed DA Form 4833 from the unit commander, the original and one copy will be sent to the apprehending Provost Marshal/Director of Emergency Services. The parent installation Provost Marshal/Director of Emergency Services may retain a copy of DA Form 3975 and DA Form 4833.

(b) *Desertion reporting procedures.* (1) The unit commander must comply with the provisions of AR 630–10 when reporting a soldier as a deserter.

(2) On receipt of the DD Form 553 (Deserter/Absentee Wanted by the Armed Forces), the Provost Marshal/Director of Emergency Services will—

(i) Initiate a DA Form 3975 and a blotter entry reflecting the soldier's desertion status.

(ii) Complete portions of DD Form 553 concerning the soldier's driver's license and vehicle identification. In the remarks section, add other information known about the soldier such as confirmed or suspected drug abuse; history of violent acts; history of escapes; attempted escapes from custody; suicidal tendencies; suspicion of involvement in crimes of violence (for which a charge sheet has been prepared and forwarded); history of unauthorized absences; and any other information useful in the apprehension process or essential to protect the deserter or apprehending authorities.

(iii) An MPR number and a USACRC control number will be assigned to the case and be included in the remarks section of the DD Form 553.

(iv) The DD Form 553 must be returned to the unit commander within 24 hours.

(v) If the deserter surrenders to or is apprehended by the parent installation Provost Marshal/Director of Emergency Services, the Provost Marshal/Director of Emergency Services will telephonically verify the deserter's status with the U.S. Army Deserter Information Point (USADIP). A

reference blotter entry will be completed changing the soldier's status from desertion to return to military control.

(vi) If the deserter surrenders to or is apprehended by an installation not the parent installation, the Provost Marshal/ Director of Emergency Services will telephonically verify the deserter's status with USADIP. An information military police report will be prepared, utilizing the CRC number from the original military police report prepared by the parent installation. A blotter entry will also be prepared.

(vii) A DD Form 616 (Report of Return of Absentee) will be completed when deserters are apprehended or surrender to military authority. The USACRC control number assigned to the DD Form 553 will be included in the remarks section of the DD Form 616.

(viii) Upon return of the deserter to military control, DA Forms 3975, 2804 (Crime Records Data), fingerprint card and 4833 will be initiated. The MPR number and USACRC control number will be recorded on all four forms.

(ix) The original DA Form 3975 and other pertinent documents will be sent to the Director, USACRC. The DA Form 4833 must include the commander's action taken, to include the Commander, Personnel Control Facility, or other commander who takes action based on the desertion charge.

§ 635.27 Vehicle Registration System.

The Vehicle Registration System (VRS) is a module within COPS. Use of VRS to register vehicles authorized access to Army installations is mandated in AR 190–5. Within VRS there are various tabs for registration of vehicles authorized access to an installation, to include personal data on the owner of the vehicle. There are also tabs for registering weapons, bicycles, and pets. Information on individuals barred entry to an installation is also maintained within VRS.

§ 635.28 Procedures for restricted/ unrestricted reporting in sexual assault cases.

Active duty Soldiers, and Army National Guard and U.S. Army Reserve Soldiers who are subject to military jurisdiction under the UCMJ, can elect either restricted or unrestricted reporting if they are the victim of a sexual assault.

(a) Unrestricted Reporting. Unrestricted reporting requires normal law enforcement reporting and investigative procedures.

(b) Restricted reporting requires that law enforcement and criminal investigative organizations not be informed of a victim's identity and not initiate investigative procedures. The victim may allow Sexual Assault Response Coordinators (SARC), health care providers (HCP), or chaplains to collect specific items (clothing, bedding, etc.) that may be later used as evidence, should the victim later decide to report the incident to law enforcement. In sexual assault cases additional forensic evidence may be collected using the ''Sexual Assault Evidence Collection Kit,'' NSN 6640–01–423–9132, or a suitable substitute (hereafter, ''evidence kit''). The evidence kit, other items such as clothing or bedding sheets, and any other articles provided by the HCP, SARC, or chaplain will be stored in the installation Provost Marshal/Directorate of Emergency Services' evidence room separate from other evidence and property. Procedures for handling evidence specified in AR 195–5, Evidence Procedures, will be strictly followed.

(c) Installation Provost Marshals/ Directors of Emergency Services will complete an information report in COPS for restricted reporting. Reports will be completed utilizing the offense code from the 6Z series. An entry will be made in the journal when the evidence kit or property (clothing, bedding, etc.) is received. The journal entry will be listed using non-identifying information, such as an anonymous identifier. An entry will not be made in the blotter. Restricted reporting incidents are not reportable as Serious Incident Reports. Property and the evidence kit will be stored for one year and then scheduled/suspensed for destruction, unless earlier released to investigative authorities in accordance with the victim's decision to pursue unrestricted reporting. Thirty days prior to destruction of the property, a letter will be sent to the SARC by the Provost Marshal/Director of Emergency Services, advising the SARC that the property will be destroyed in thirty days, unless law enforcement personnel are notified by the SARC that the victim has elected unrestricted reporting. Clothing, the evidence kit, or other personal effects may be released to the SARC for return to the victim. The information report will be updated when the evidence is destroyed, or released to investigative authorities.

(d) In the event that information about a sexual assault that was made under restricted reporting is disclosed to the commander from a source independent of the restricted reporting avenues or to law enforcement from other sources, but from a source other than the SARC, HCP, chaplain, or Provost Marshal/ Director of Emergency Services, the commander may report the matter to law enforcement and law enforcement remains authorized to initiate its own independent investigation of the matter presented. Additionally, a victim's disclosure of his/her sexual assault to persons outside the protective sphere of the persons covered by the restricted reporting policy may result in an investigation of the allegations.

§ 635.29 Domestic violence and protection orders.

(a) Responding to incidents of spouse abuse requires a coordinated effort by law enforcement, medical, and social work personnel, to include sharing information and records as permitted by law and regulation. AR 608–18 contains additional information about domestic violence and protective orders.

(b) Appendix C of AR 190–45 includes specific offense codes for domestic violence. All domestic violence incidents will be reported to the local PMO. All reported domestic violence incidents will be entered into MPRS, utilizing DA Form 3975. These codes will be utilized in addition to any other offense code that may be appropriate for an incident. For example, a soldier strikes his or her spouse. When entering the offense data into MPRS, both the offense code for assault (i.e. 5C2B) and the offense code for spouse abuse (from the 5D6 series) will be entered.

(c) A military Protection Order is a written lawful order issued by a commander that orders a soldier to avoid contact with his or her spouse or children. Violations of a military Protection Order must be reported on DA Form 3975, entered into COPS, and entered into NCIC. Violations of a military Protection Order may be violations of Article 92, UCMJ. The commander should provide a written copy of the order within 24 hours of its issuance to the person with whom the member is ordered not to have contact. A copy should be forwarded to the installation Family Advocacy Program Manager (FAPM), the Chief, Social Work Service, and the installation military police.

(d) A civilian Protection Order is an order issued by a judge, magistrate or other authorized civilian official, ordering an individual to avoid contact with his or her spouse or children. Pursuant to the Armed Forces Domestic Security Act a civilian protection order has the same force and effect on a military installation as such order has within the jurisdiction of the court that issued the order. Violations of a civilian Protection Order must be reported on

DA Form 3975, entered into COPS, and entered into NCIC.

§ 635.30 Establishing Domestic Violence Memoranda of Understanding.

(a) Coordination between military law enforcement personnel and local civilian law enforcement personnel is essential to improve information sharing, especially concerning domestic violence investigations, arrests, and prosecutions involving military personnel. Provost Marshals/Directors of Emergency Services or other law enforcement officials shall seek to establish formal Memoranda of Understanding (MOU) with their civilian counterparts to establish or improve the flow of information between their agencies, especially in instances of domestic violence involving military personnel. MOUs can be used to clarify jurisdictional issues for the investigation of incidents, to define the mechanism whereby local law enforcement reports involving active duty service members will be forwarded to the appropriate installation law enforcement office, to encourage the local law enforcement agency to refer victims of domestic violence to the installation Family Advocacy office or victim advocate, and to foster cooperation and collaboration between the installation law enforcement agency and local civilian agencies.

(b) MOUs should address the following issues:

(1) A general statement of the purpose of the MOU.

(2) An explanation of jurisdictional issues that affect respective responsibilities to and investigating incidents occurring on and off the installation. This section should also address jurisdictional issues when a civilian order of protection is violated on military property (see 10 U.S.C. 1561a).

(3) Procedures for responding to domestic violence incidents that occur on the installation involving a civilian alleged offender.

(4) Procedures for transmitting incident/investigation reports and other law enforcement information on domestic violence involving active duty service members from local civilian law enforcement agencies to the installation law enforcement office.

(5) Procedures for transmitting civilian protection orders (CPOs) issued by civilian courts or magistrates involving active duty service members from local law enforcement agencies to the installation law enforcement office.

(6) Designation of the title of the installation law enforcement recipient of such information from the local law enforcement agency.

(7) Procedures for transmitting military protection orders (MPOs) from the installation law enforcement office to the local civilian law enforcement agency with jurisdiction over the area in which the service member resides.

(8) Designation of the title of the local law enforcement agency recipient of domestic violence and CPO information from the installation law enforcement agency.

(9) Respective responsibilities for providing information to domestic violence victims regarding installation resources when either the victim or the alleged offender is an active duty service member.

(10) Sharing of information and facilities during the course of an investigation in accordance with the Privacy Act of 1974 (see 5 U.S.C. 552a(b)(7)).

(11) Regular meetings between the local civilian law enforcement agency and the installation law enforcement office to review cases and MOU procedures.

§ 635.31 Lost, abandoned, or unclaimed property.

This is personal property that comes into the possession, custody, or control of the Army and is unclaimed by the owner. Property is considered to be abandoned only after diligent effort has been made to determine and locate its owner, the heir, next of kin, or legal representative. A military person who is ordered overseas and is unable to dispose of their personal property should immediately notify their chain-of-command. The commander will appoint a board to rule on the disposition of the property. If a law enforcement agency takes custody of the property it will be tagged and a record made as shown in paragraph (a) of this section. A report will be made to the installation commander who will take action in accordance with DOD 4160.21–M, chapter 4, paragraph 40, Defense Materiel Disposition Manual. Pending board action under DOD 4160.21–M, the law enforcement agency having physical custody is responsible for the safekeeping of seized property. The following procedures should be used:

(a) Property will be tagged using DA Form 4002 (Evidence/Property Tag) or clearly identified by other means, inventoried, and made a matter of record. These records are kept by the custodian of the property.

(b) Lost, abandoned, or unclaimed property will be kept in a room or container separate from one used to store property held as evidence. Records or logs of property not held as evidence will be separated from those pertaining to evidence. However, all property will be tagged, accounted for, and receipted for in a similar manner as evidence.

(c) Property that has been properly identified through board action under DOD 4160.21–M as having an owner will be segregated and tagged with the name of that person.

(d) Abandoned or unclaimed property will be held until its status can be determined. In many instances, lost property can be returned to the owner upon presentation of proof of ownership.

(e) In all cases, a receipt should be obtained at time of release.

Subpart D—Army Quarterly Trends and Analysis Report

§ 635.32 General.

(a) This subpart prescribes policies and procedures for the coordination and standardization of crime statistics reporting with HQDA. Crime statistical reports and trends provided to HQDA and other agencies and those related to special interests inquiries, the media, and the public must reflect uniformity in terminology, methods of presentation, and statistical portrayal to preclude misinterpretation of information.

(b) Any report containing Army-wide aggregate crime data or statistics addressed to the Secretary of the Army, Chief of Staff of the Army, or Vice Chief of Staff of the Army will be coordinated and cleared with HQDA, Office of the Provost Marshal General (DAPM–MPD–LE). Correspondence and reports will be coordinated with HQDA, Office of the Provost Marshal General (DAPM–MPD–LE) prior to release to any agency, activity, or individual.

(c) HQDA staff agencies ACOM, ASCC and DRU authorized by regulation or statute to conduct independent investigations, audits, analyses, or inquiries need not coordinate reported information with HQDA, Office of the Provost Marshal General (DAPM–MPD–LE) unless the information contains crime data for the Army as a whole. For example, reports submitted by USACIDC containing only USACIDC investigative data need not be coordinated with HQDA, Office of the Provost Marshal General (DAPM–MPD–LE).

§ 635.33 Crime rate reporting.

(a) The USACRC is the Army's collection point and analytic center for all Army aggregate crime data. Requests for Army-wide crime data reports will

be forwarded through HQDA, Office of the Provost Marshal General (DAPM–MPD–LE) to the Director, USACRC. Replies will be routed back through HQDA Office of the Provost Marshal General (DAPM–MPD–LE) where they will be coordinated, as appropriate, prior to release. Requests for USACIDC, ACOM, ASCC, DRU, or subordinate command specific crime data reports can be made directly to the specific command. Replies need not be coordinated with HQDA.

(b) Requests for Army aggregate crime reports are limited to data collected and accessible through the Automated Criminal Investigation and Intelligence System (ACI2) and COPS.

(c) Routine collection of ACOM, ASCC or DRU crime data, for use in Army-wide database, will be limited to that data collected by the above systems. ACOM, ASCC and DRU may determine internal data collection requirements.

(d) All Provost Marshal/Director of Emergency Services crime data will be recorded and forwarded by installations through ACOM, ASCC or DRU using the COPS system.

(e) In support of the Secretary Of the Army and the Office of the Chief of Staff of the Army, the Chief, Operations Division, Office of the Provost Marshal General, will determine the requirements for routine publication of Army aggregate crime statistics.

(f) Normally, raw data will not be released without analysis on routine or non-routine requests. Comparison of ACOM, ASCC or DRU crime data is generally not reported and should be avoided. General categories of CONUS or OCONUS are appropriate.

Subpart E—Victim and Witness Assistance Procedures

§ 635.34 General.

(a) This subpart implements procedures to provide assistance to victims and witnesses of crimes that take place on Army installations and activities. The procedures in this subpart apply to—

(1) Every victim and witness.

(2) Violations of the UCMJ, including crimes assimilated under the Assimilative Crimes Act reported to or investigated by military police.

(3) Foreign nationals employed or visiting on an Army installation OCONUS.

(b) Provost Marshal/Director of Emergency Services personnel should refer to AR 27–10, Chapter 18, for additional policy guidance on the Army Victim/Witness Program.

§ 635.35 Procedures.

(a) As required by Federal law, Army personnel involved in the detection, investigation, and prosecution of crimes must ensure that victims and witnesses rights are protected. Victims rights include—

(1) The right to be treated with fairness, dignity, and a respect for privacy.

(2) The right to be reasonably protected from the accused offender.

(3) The right to be notified of court proceedings.

(4) The right to be present at all public court proceedings related to the offense, unless the court determines that testimony by the victim would be materially affected if the victim heard other testimony at trial, or for other good cause.

(5) The right to confer with the attorney for the Government in the case.

(6) The right to restitution, if appropriate.

(7) The right to information regarding conviction, sentencing, imprisonment, and release of the offender from custody.

(b) In keeping with the requirements listed in paragraph (a) of this section, Provost Marshals/Directors of Emergency Services must ensure that—

(1) All law enforcement personnel are provided copies of DD Form 2701 (Initial Information for Victims and Witnesses of Crime).

(2) A victim witness coordinator is appointed in writing.

(3) Statistics are collected and reported into COPS.

(4) Coordination with the installation staff judge advocate victim witness coordinator occurs to ensure that individuals are properly referred for information on restitution, administrative, and judicial proceedings.

(5) Coordination with installation Family Advocacy Program's Victim Advocate occurs to support victims of spouse abuse. Victim Advocacy services include crisis intervention, assistance in securing medical treatment for injuries, information on legal rights and proceedings, and referral to military and civilian shelters and other resources available to victims.

§ 635.36 Notification.

(a) In addition to providing crime victims and witnesses a DD Form 2701, law enforcement personnel must ensure that individuals are notified about—

(1) Available military and civilian emergency medical care.

(2) Social services, when necessary.

(3) Procedures to contact the staff judge advocate victim/witness liaison office for additional assistance.

(b) Investigating law enforcement personnel, such as military police investigators—

(1) Must ensure that victims and witnesses have been offered a DD Form 2701. If not, investigating personnel will give the individual a copy.

(2) In coordination with the Provost Marshal/Director of Emergency Services victim witness coordinator, provide status on investigation of the crime to the extent that releasing such information does not jeopardize the investigation.

(3) Will, if requested, inform all victims and witnesses of the apprehension of a suspected offender.

§ 635.37 Statistical reporting requirements.

(a) DOD policies on victim witness assistance require reporting of statistics on the number of individuals who are notified of their rights. The DA Form 3975 provides for the collection of statistical information.

(b) The COPS system supports automated reporting of statistics. HQDA, Office of the Provost Marshal General (DAPM–MPD–LE) as the program manager may require periodic reports to meet unique requests for information.

(c) It is possible that a victim or witness may initially decline a DD Form 2701. As the case progresses, the individual may request information. If a case is still open in the Provost Marshal Office/Directorate of Emergency Services, the Provost Marshal/Director of Emergency Services victim witness coordinator shall provide the DA Form 2701 to the individual and update the records. Once the case is referred to the staff judge advocate or law enforcement activity ceases, COPS will not be updated without prior coordination with the installation Staff Judge Advocate office.

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 35

[EPA–HQ–OW–2006–0765; FRL7–8288–1]

Reopening of Public Comment Period for the NPDES Permit Fee Incentive for Clean Water Act Section 106 Grants; Allotment Formula

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed Rulemaking; Reopening of the public comment period.

SUMMARY: On Thursday, January 4, 2007, the Environmental Protection Agency published a proposed rule entitled ''NPDES Permit Fee Incentive for Clean Water Act Section 106 Grants; Allotment Formula.'' Written comments on the proposed rulemaking were required to be submitted to EPA on or before March 5, 2007, (a 60-day public comment period). EPA has received several requests for additional time to submit comments on the proposed rule. Therefore, the public comment period is being reopened for an additional 60-day comment period.

DATES: Comments must be received on or before May 14, 2007.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OW–2006–0765 by one of the following methods:

- *http://www.regulations.gov:* Follow the on-line instructions for submitting comments.
- *E-mail: ow-docket@epa.gov* Attention Docket ID No. OW–2006–0765.
- *Mail*: Water Docket, Environmental Protection Agency, Mailcode: 2822T, 1200 Pennsylvania Ave., N.W., Washington, DC 20460.
- *Hand Delivery:* EPA Docket Center, EPA West, Room 3334, 1301 Constitution Avenue, NW, Washington, DC, Attention Docket ID No. OW–2006–0765. Such deliveries are only accepted during the Docket's normal hours of operation and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA–HQ–OW–2006–0765. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through www.regulations.gov or e-mail. The *www.regulations.gov* Web site is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *www.regulations.gov*, your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional information about EPA's public docket, visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.*

Docket: All documents in the docket are listed in the *www.regulations.gov* index. Although listed in the index, some information is not publicly available, e.g., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the Water Docket, EPA/DC, EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Water Docket is (202) 566–2426.

FOR FURTHER INFORMATION CONTACT: Lena Ferris, Office of Water, Office of Wastewater Management, 4201M, Environmental Protection Agency, 1200 Pennsylvania Avenue, NW., Washington, DC 20460; telephone number: (202) 564–8831; fax number: (202) 501–2399; e-mail address: *ferris.lena@epa.gov* .

Dated: March 9, 2007.

James A. Hanlon,

Director, Office of Wastewater Management.

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DEPARTMENT OF TRANSPORTATION

National Highway Traffic Safety Administration

49 CFR Parts 531 and 533

[Docket No. NHTSA–2007–27350]

Corporate Average Fuel Economy—Request for Product Plan Information for Model Year 2007–2017 Passenger Cars and 2010–2017 Light Trucks

AGENCY: National Highway Traffic Safety Administration (NHTSA), Department of Transportation (DOT).

ACTION: Request for comments; correction.

SUMMARY: This document corrects the dates and addresses captions in a request for comments published in the **Federal Register** of February 27, 2007 (72 FR 8664), regarding the acquisition of new and updated manufacturers' future product plans to aid in implementing the President's plan for reforming and increasing corporate average fuel economy (CAFE) standards for passenger cars and further increasing the already reformed light truck standards. The DATES caption did not include the correct date for submission of light truck product plans, and the addresses caption did not include a complete docket number.

FOR FURTHER INFORMATION CONTACT: Ken Katz, (202) 366–4936.

Correction

In the **Federal Register** of February 27, 2007, in FR Doc. 07–878, make the following corrections. On page 8664, in the third column, correct the DATES caption to read:

DATES: Passenger car comments must be received on or before May 29, 2007. Light truck comments must be received on or before June 27, 2007.

On page 8664, in the third column, correct the first three lines of the ADDRESSES caption to read:

ADDRESSES: You may submit comments [identified by DOT DMS Docket Number 2007–27350] by any of the following methods:

Issued: March 9, 2007.

Stephen R. Kratzke,

Associate Administrator for Rulemaking.

[FR Doc. E7–4765 Filed 3–14–07; 8:45 am]

BILLING CODE 4910–59–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 635

[Docket No. 070307055–7055–01; I.D. 022607F]

RIN 0648–AV25

Atlantic Highly Migratory Species (HMS); U.S. Atlantic Billfish Tournament Management Measures

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Proposed rule; request for comments.

SUMMARY: NMFS proposes to temporarily suspend circle hook requirements for anglers participating in Atlantic billfish tournaments. The final rule implementing the Final Consolidated HMS Fishery Management Plan (FCHMS FMP) published in the **Federal Register** on October 2, 2006, and restricted anglers fishing from HMS permitted vessels and participating in Atlantic billfish tournaments to deploying only non-offset circle hooks when using natural baits or natural bait/artificial lure combinations, effective 12:01 am, January 1, 2007. The purpose of the final rule was to reduce post-release mortality of Atlantic billfish and other species with which billfish tournament anglers may interact. NMFS has continued to receive public comment since publication of the Final CHMS FMP regarding the perceived impacts of the billfish tournament non-offset circle hook requirement. The objective of this proposed rulemaking is to increase post-release survival of Atlantic billfishes by improving long-term compliance with billfish tournament non-offset circle hook regulations.

DATES: Written comments on the proposed rule must be received by March 30, 2007.

ADDRESSES: Written comments on the proposed rule or the Draft Environmental Assessment (Draft EA) may be submitted to Russell Dunn or Randy Blankinship, Fisheries Management Specialists, Highly Migratory Species Management Division, using any of the following methods:

- *E-mail: 0648–AV25@noaa.gov* Please include the following in the subject line: ''Comments on Proposed Billfish Circle Hook Rule.''
- *Mail:* NOAA/NMFS HMS Management Division, 263 13th Avenue South, St. Petersburg, FL 33701. Please mark the outside of the envelope ''Comments on Proposed Billfish Circle Hook Rule''.
- *Fax:* 727–824–5398.
- *Federal e-Rulemaking Portal: http://www.regulations.gov*. Include in the subject line the following identifier: ''I.D. 022607F.''

The hearing locations are:

1. March 27, 2007 from 7 – 9 p.m. Worcester County Library, Snow Hill Branch, 307 North Washington Street, Snow Hill, Maryland, 21863.

2. March 28, 2007 from 7 – 9 p.m. Broward County Library, Main Library, 100 South Andrews Avenue, Ft. Lauderdale, FL 33301.

3. March 29, 2007 from 7 – 9 p.m. Carteret Community College, Joslyn Hall, H.J. McGee, Jr. Building, 3505 Arendell Street, Morehead City, NC 28557–2989.

Copies of the Draft EA, the 2006 FCHMS FMP and other relevant documents are available from the Highly Migratory Species Management Division website at *http://www.nmfs.noaa.gov/sfa/hms* or by contacting Russell Dunn or Randy Blankinship (see **FOR FURTHER INFORMATION CONTACT**).

FOR FURTHER INFORMATION CONTACT: Russell Dunn or Randy Blankinship, by phone: 727–824–5399; by fax: 727–824–5398.

SUPPLEMENTARY INFORMATION:

Background

The U.S. recreational fishery for Atlantic billfish is managed under the Consolidated HMS FMP. Implementing regulations at 50 CFR part 635 are issued under the authority of the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act)(16 U.S.C. 1801 *et seq.*), and the Atlantic Tunas Convention Act (ATCA) (16 U.S.C. 971 *et seq.*).

Atlantic billfish management strategies have been guided by international and domestic considerations and mechanisms since the 1970s. Domestic management of Atlantic billfish resources has been developed, modified, and implemented in four primary stages and through a series of other rulemakings. In January 1978, NMFS published the Preliminary Fishery Management Plan (PMP) for Atlantic Billfish and Sharks (43 FR 3818), which was supported by an EIS (42 FR 57716). This PMP was developed and implemented under the authority of the Secretary of Commerce.

Building upon the PMP for Atlantic Billfish and Sharks was the Fishery Management Plan for the Atlantic Billfishes (53 FR 21501). This plan was jointly developed by five Atlantic regional fishery management councils (Caribbean, Gulf, South Atlantic, Mid-Atlantic, New England) and implemented in October 1988 (53 FR 37765). The 1988 FMP defined the Atlantic billfish management unit to include sailfish from the western Atlantic Ocean, white marlin and blue marlin from the North Atlantic Ocean, and longbill spearfish from the entire Atlantic Ocean; described objectives for the Atlantic billfish fishery; and established management measures to achieve the objectives.

Atlantic blue and white marlin were identified as overfished in 1997 and Atlantic sailfish were identified as overfished in 1998. In response to Magnuson-Stevens Act requirements, and concurrent with efforts to develop the 1999 FMP for Atlantic Tunas, Swordfish, and Sharks, NMFS prepared Amendment One to the Atlantic Billfish Fishery Management Plan and published final regulations on May 28, 1999 (64 FR 29090). Amendment One maintained the objectives of the original 1988 Billfish FMP and identified a number of additional objectives. On Oct. 2, 2006 (71 FR 58057), NMFS issued the final rule implementing the Final Consolidated HMS FMP. That document amended and consolidated the objectives and management measures of the Atlantic Billfish Fishery FMP with those of the 1999 Atlantic Tunas, Swordfish, and Sharks FMP, among other actions.

The recent biomass level of Atlantic blue marlin most likely remains well below the level necessary to produce the maximum sustainable yield (B_{msy}) that was estimated in 2000. Current and provisional estimates suggest that the fishing mortality rate (F) has recently declined and is possibly smaller than $F_{replacement}$, but larger than the F_{msy} estimated in the 2000 assessment. Over the period 2001 - 2005, several abundance indicators suggest that the decline in biomass has been at least partially arrested, but some other indicators suggest that abundance has continued to decline.

The 1996, 2000, and 2002 stock assessments for white marlin all indicated that biomass of white marlin has been below B_{msy} for more than two decades and the stock is overfished. The recent biomass of Atlantic white marlin most likely remains well below the B_{msy} estimated in the 2002 assessment. Current and provisional estimates suggest that F is probably smaller than $F_{replacement}$ and probably also larger than the F_{msy} estimated in the 2002

assessment. Over the period 2001–2004, combined longline indices and some individual fleet indices suggest that the decline has been at least partially reversed, but some other individual fleet indices suggest that abundance has continued to decline.

In 2002, the United States undertook a status review of white marlin pursuant to the Endangered Species Act (ESA). The status review team determined that white marlin stock status did not warrant a listing at that time. NMFS was subsequently sued with regard to its determination not to list Atlantic white marlin as endangered at that time. In accordance with a court approved settlement agreement, NMFS has initiated a second ESA listing review for Atlantic white marlin that will be completed by December 31, 2007.

Prior to January 1, 2007, the recreational Atlantic billfish fishery was subject to regulations that required fishing permits, limited allowable gears to rod and reel only, established minimum legal size limits, specified landing form of retained billfish, mandated reporting of billfish landings, required registration of all recreational HMS fishing tournaments and reporting by tournaments that are selected for reporting, prohibited the retention of longbill spearfish, and prohibited sale of any billfish, among others. The final rule implementing the FCHMS FMP (October 2, 2006; 71 FR 58058) implemented additional regulations that applied to the Atlantic recreational billfish fishery. These regulations became effective January 1, 2007, and limited U.S. landings of Atlantic blue and white marlin to 250 individual fish, combined, on an annual basis. The final rule also implemented regulations that require anglers fishing from HMS permitted vessels and participating in Atlantic billfish tournaments to use only non-offset circle hooks when deploying natural baits or natural bait/artificial lure combinations. These regulations allow the use of traditional J-hooks with artificial lures in tournaments, and do not impose hook requirements on recreational fishermen fishing outside of Atlantic billfish tournaments.

NMFS implemented circle hook regulations in the FCHMS FMP consistent with the objectives of the FMP, including reducing post-release mortality of Atlantic billfish. Atlantic billfish tournament circle hook requirements were determined to be an effective mechanism to target a known source of billfish mortality in the directed recreational marlin fishery. Recent studies have shown that circle hooks can substantially reduce injury and post-hooking mortality of Atlantic billfish and other species relative to J-hooks. Horodysky and Graves (2005) found that circle hooks can reduce post-release mortality of white marlin by 65.7 percent relative to J-hooks. They also found that white marlin caught on J-hooks are 41 times more likely to be deeply hooked and 15 times more likely to sustain hook-induced trauma resulting in bleeding relative to fish caught on circle hooks. Prince *et al.* (2002), found similar results pertaining to sailfish. Prince *et al.*, also found no statistical difference in catch per unit of effort between circle hooks and J-hooks when fishing for blue marlin. Cooke and Suski (2004) analyzed the results of more than 40 circle hook studies examining both marine and fresh water species. For all species examined, they found that mortality rates were approximately 50 percent lower when using circle hooks relative to J-hooks. During the analysis of the FCHMS FMP, NMFS found that between 1999 and 2004, the number of Atlantic white marlin released alive during tournaments ranged from a low of 614 to a high of 2,207. Based on an estimated 35 percent post-release mortality rate for white marlin caught on J-hooks (Horodysky and Graves, 2005), this would equate to between 215 and 773 Atlantic white marlin that would not be expected to survive the catch and release experience. Applying an estimated 12 percent post-release mortality rate for white marlin caught on circle hooks (Horodysky and Graves, 2005) to the same number of released white marlin, this would equate to between 74 and 265 Atlantic white marlin that would not be expected to survive the catch and release experience. The difference between the two indicated a potential ecological benefit of between 141 and 508 Atlantic white marlin surviving the catch and release experience if anglers used circle hooks in tournaments rather then J-hooks.

NMFS has continued to receive public comment on the perceived impacts of the billfish tournament circle hook requirement contained in the FCHMS FMP since release of that document in July of 2006. This included comments by anglers indicating that circle hooks will not work well for catching blue marlin; expressing a desire by anglers to continue using J-hooks while fishing for Atlantic blue marlin in tournaments; and noting that deploying J-hooks on mixed-baits with heavy fishing gear was an effective and popular technique employed by anglers during fishing tournaments. Comments also stated that fishing for billfish with J-hooks trolled at high speeds with heavy tackle did not result in high post-release hooking mortalities of Atlantic billfish species. Finally, some commenters supported full implementation of tournament circle hook requirements. In response to these concerns, NMFS considered development of an exempted fishing permit (EFP) program to collect additional data on this fishing activity in billfish tournaments. Comments received on the development of an EFP program to collect data within billfish tournaments expressed concern over the difficulty of standardizing fishing gear type and use in a tournament setting; concern over the quality of data collected in a tournament setting; and the scientific applicability of such data given the fishing characteristics of tournaments (fast paced activity, focus on catching and retaining specific species and/or size classes, and varying tournament rules), among others. Finally, comments were received that expressed a general lack of support for conducting research and/or data.

Based on public comment, NMFS has since determined that the collection of data to evaluate the impacts of J-hooks and heavy tackle on Atlantic blue marlin during billfish tournaments would be problematic because of the varying conditions and methodologies discussed above that would likely occur within and between tournaments, among others. For these reasons, NMFS chose not to issue EFPs to Atlantic billfish tournaments (72 FR 4691; February 1, 2007). Available data indicate that hook type (circle hook versus J-hook) is not a major factor influencing catch rates of blue marlin. Nevertheless, many anglers believe circle hooks to be ineffective and that J-hooks can be deployed in a manner resulting in low post-release mortality. The result has been strong resistance to implementation of circle hooks in certain circumstances and regions. Available studies clearly demonstrate the benefits of circle hooks for billfish and other species, and NMFS believes that concerns over the effectiveness of circle hooks when fishing for Atlantic blue marlin, as well as resistance to their use by tournament anglers, can be overcome as anglers become more familiar and proficient with them.

In this action, NMFS proposes to temporarily suspend existing regulations that require Atlantic billfish tournament participants who are fishing from HMS permitted vessels and deploying natural bait or natural bait/artificial lure combinations to use non-offset circle hooks. The preferred alternative is intended to increase post-release survival of Atlantic billfishes by

improving long-term compliance with circle hook regulations. To accomplish this, the proposed rule would provide additional time for recreational billfish tournament anglers to become more familiar and proficient with circle hooks and increase awareness among tournament anglers of circle hook conservation benefits. NMFS has received input from numerous anglers and tournament operators who voluntarily switched to using circle hooks prior to the existing tournament requirement who now indicate a strong preference for circle hooks over J-hooks based on conservation benefits and who claim a lower rate of lost fish on circle hooks. Based on the economic incentives discussed above, the input from experienced billfish anglers who have acquired expertise with circle hooks, and existing studies (Prince *et al.*, 2002) indicating that hook type (circle hook vs. J-hook) is not a significant factor in catchability of Atlantic blue marlin, NMFS is confident that the concerns of anglers regarding the effectiveness of circle hooks for catching blue marlin and the resistance to using circle hooks stemming from preconceived ideas of circle hook efficacy and a lack of experience with circle hooks will be overcome if anglers are given more time to become familiar and proficient with them through an additional phase-in period.

Fishing techniques vary by species, region, time of day, weather conditions, type of gear and bait deployed, and numerous other factors. There are significant differences in the techniques employed by fishermen when using J-hooks or circle hooks. Two examples are the technique of ''setting the hook'' with J-hooks and baiting techniques. With J-hooks, anglers are taught to ''set the hook'' at a given time by jerking hard on the pole and line. This action is meant to drive the point of the J-hook deep into the flesh of the fish to help ensure that the fish cannot escape by throwing the hook loose during the fight. With circle hooks, setting the hook is ineffective because of the hook shape and is a technique that often leads to a loss of the fish. Anglers must not set the hook, but rather wait for the fish to hook itself. This is a significant change in fishing technique for virtually all anglers and learning the subtleties of effective circle hook fishing can take a significant amount of practice. Baiting techniques or configurations can substantially vary between J-hooks and circle hooks. One example is with J-hooks, fishermen may bury the J-hook in the body of the bait, with only the point exposed through a slit in the stomach. With circle hooks, the hook must be free of obstructions and is thus sometimes attached to a halter made of fishing line above the head of a bait by rubber bands. Baiting techniques for circle hooks vary by bait species and target species. It may take a substantial amount of time for anglers to learn new baiting techniques effective with circle hooks.

This proposed rule would suspend existing Atlantic billfish tournament circle hook regulations until January 1, 2008, providing approximately seven months for anglers to learn fishing and baiting techniques appropriate for Atlantic billfishes prior to re-implementation of tournament circle hook requirements. As discussed above, NMFS is confident that the provision of additional time for anglers to adjust to circle hook fishing and baiting techniques will help assuage the concerns of anglers and lead to increased compliance with circle hook requirements.

As of January 29, 2007, the potential universe of affected anglers includes: 24,664 HMS Angling category permit holders; 4,140 HMS Charter/Headboat category permit holders, and 4,345 General Category permit holders. All of the aforementioned permit holders are eligible to participate in registered Atlantic HMS tournaments.

This proposed rule would be expected to have limited short-term adverse ecological impacts as it would temporarily suspend billfish tournament non-offset circle hook requirements for a limited period of time; approximately seven months (May 15 - December 31). This may result in temporary increases in injuries and post-release mortalities for species with which Atlantic billfish fishermen interact. Tournament catch data indicate that tournament interactions with billfish decline to relatively low levels during the last quarter of the year (October - December), with the exception being blue marlin in Puerto Rico. An examination of the tournament catch data indicate that the preferred alternative could result in approximately 317 additional Atlantic white marlin mortalities as a result of J-hook use instead of circle hook use in tournaments. As NMFS cannot quantify the proportion of anglers who may continue to use non-offset circle hooks in billfish tournaments, this estimate assumes all billfish tournament anglers will deploy J-hooks for the period May 15, 2007 - December 31, 2007. NMFS is unable to quantify relative changes in mortality for Atlantic blue marlin or sailfish because of a lack of data regarding post-release survival of these species. NMFS recognizes that some unquantifiable proportion of billfish tournament anglers will continue to use circle hooks. As a result, the actual number of additional Atlantic white marlin mortalities resulting from J-hook use in tournaments may be lower than the estimate provided above.

The preferred alternative that would suspend billfish tournament circle hook requirements and allow the use of J-hooks on natural baits is not anticipated to increase fishing effort in any measurable way because no decrease in effort was anticipated when tournament circle hook requirements went into effect. Based on the pace of 2007 tournament registrations, no decrease has been identified, and in fact, tournament registrations for 2007 have been received at a near record pace. It is also not anticipated to result in increased interactions with protected resources. NMFS has received one anecdotal report of such an interaction in HMS recreational fisheries since late 2002. Thus, interactions between the directed Atlantic billfish fishery and protected species appear to be extremely rare. Further, if the proposed rule results in improved long term compliance with circle hook requirements, as anticipated, it may also contribute to a long-term reduction in interactions, injuries, and mortalities of protected resources, and other species with which billfish tournament fishermen interact as a result of hooking mechanics, improved hooking location, and decreased damage of vital tissues generally associated with the use of circle hooks.

Should anglers better accept and comply with tournament circle hook restrictions in the long-term as anticipated, NMFS believes that there could be an unquantifiable long-term ecological benefit stemming from increased use of circle hooks both in tournaments and outside of tournaments. The non-tournament ecological benefit may accrue as non-tournament anglers frequently view tournament anglers as innovative leaders and seek to emulate their successful fishing techniques. NMFS believes that this pattern of non-tournament anglers emulating the fishing techniques of successful tournament anglers will hold true with the adoption of circle hooks by tournament anglers as well.

Under the proposed measure, NMFS anticipates minimal social or economic impacts. Atlantic billfish anglers likely already possess both circle hooks and J-hooks, and the proposed measure is not anticipated to affect angler participation in tournaments. However, there could be a minor temporary boost to angler's

willingness to pay and/or angler consumer surplus based on the perceived ability to more readily catch Atlantic billfish on J-hooks. As stated above, any such changes would likely be so small as to be not measurable. Long-term positive impacts on angler's willingness to pay and/or angler consumer surplus are possible if increased acceptance of circle hooks in tournaments contributes to stock rebuilding and an increased abundance of Atlantic billfish in the future. This measure is proposed because it could lead to increased survival of released Atlantic billfish in the long-term by improving acceptance and compliance with recreational circle hook regulations, and thus contribute to rebuilding of these stocks.

Classification

This proposed rule is published under the authority of the Magnuson-Stevens Act and ATCA. NMFS has preliminarily determined that this action is consistent with section 304(b)(1) of the Magnuson-Stevens Act, including the national standards, and other applicable law.

An EA has been prepared that describes the impact on the human environment that could result from implementation of the preferred alternative to improve post-release survival of Atlantic billfishes by improving acceptance and compliance with tournament circle hook regulations. Based on the EA, Regulatory Impact Review (RIR), and Initial Regulatory Flexibility Analysis (IRFA) under the Regulatory Flexibility Act, and a review of the National Environmental Policy Act (NEPA) criteria for significance evaluated above (NAO 216–6 Section 6.02), no significant effect on the quality of the human environment is anticipated from this action.

This proposed rule has been determined to be not significant for purposes of Executive Order 12866. In compliance with Section 603 of the Regulatory Flexibility Act, an Initial Regulatory Flexibility Analysis was prepared for this rule. The IRFA analyzes the anticipated economic impacts of the preferred actions and any significant alternatives to the proposed rule that could minimize economic impacts on small entities. A summary of the IRFA is below. The full IRFA and analysis of economic and ecological impacts are available from NMFS (see **ADDRESSES**).

In compliance with Section 603(b)(1) and (2) of the Regulatory Flexibility Act, the purpose of this proposed rulemaking is, consistent with the Magnuson-Stevens Act and ATCA, to improve post-release survival of Atlantic billfishes by improving acceptance and compliance with tournament circle hook regulations. Section 603(b)(3) requires Agencies to provide an estimate of the number of small entities to which the rule would apply. The proposed actions to modify recreational billfish tournament circle hook regulations could directly affect 24,664 HMS Angling category permit holders; 4,140 HMS Charter/Headboat category permit holders; and 4,345 General Category permit holders. All of the aforementioned permit holders are eligible to participate in registered Atlantic HMS tournaments. Of these, 8,475 permit holders (the combined number of HMS Charter/Headboat category permit holders and General Category permit holders) are considered small business entities according to the Small Business Administration's standard for defining a small entity.

This proposed rule does not contain any new reporting, record keeping, or other compliance requirements (5 U.S.C. 603(c)(1)-(4)). Similarly, this proposed rule does not conflict, duplicate, or overlap with other relevant Federal rules (5 U.S.C. 603(b)(5).

One of the requirements of an IRFA, under Section 603 of the Regulatory flexibility Act, is to describe any alternatives to the proposed rule that accomplish the stated objectives and that minimize any significant economic impacts (5 U.S.C. 603(c)). Additionally, the Regulatory Flexibility Act (5 U.S.C. 603 (c)(1)-(4)) lists four categories for alternatives that must be considered. These categories are: (1) establishment of differing compliance or reporting requirements or timetables that take into account the resources available to small entities; (2) clarification, consolidation, or simplification of compliance and reporting requirements under the rule for such small entities; (3) use of performance rather than design standards; and (4) exemptions from coverage for small entities.

In order to meet the objectives of this proposed rule, consistent with the Magnuson-Stevens Act, ATCA, and the Endangered Species Act (ESA), NMFS cannot exempt small entities or change the reporting requirements only for small entities. Thus, there are no alternatives that fall under the first and fourth categories described above. In addition, none of the alternatives considered would result in additional reporting or compliance requirements (category two above). NMFS does not know of any performance or design standards that would satisfy the aforementioned objectives of this rulemaking while, concurrently, complying with the Magnuson-Stevens Act.

NMFS considered three different alternatives to increase post-release survival of Atlantic billfishes by improving long-term compliance with circle hook regulations. As previously described, and as expanded upon below, NMFS has provided justification for the selection of the preferred alternative to achieve the desired objectives.

Alternative 1 is the no action, or status quo alternative. Under current regulations, anglers fishing from an HMS permitted vessel and participating in an Atlantic billfish tournament must use only non-offset circle hooks when deploying natural bait or natural bait/artificial lure combinations. Under alternative 1, there would be no change in the existing regulations, and as such no change is anticipated in the current baseline economic and social impacts associated with the status quo alternative. This alternative is not preferred because other alternatives may allow for a greater long-term conservation benefit for Atlantic billfish by potentially achieving better acceptance of, and compliance with, tournament circle hook requirements.

Under alternative 2, existing Atlantic billfish tournament circle hook requirements, as described in the discussion of alternative 1 above, would be temporarily suspended through December 31, 2007. Current Atlantic billfish tournament circle hook requirements would be reinstated unchanged at 12:01 am January 1, 2008. This alternative would provide roughly seven additional months for anglers to become familiar and proficient with circle hooks as well as better understand their benefits. NMFS anticipates that tournament anglers will practice with circle hooks outside of tournaments during the suspension to gain proficiency with circle hooks to improve their chances of winning prize money in tournaments upon re-implementation of the circle hook requirement in 2008. Motivation for anglers to do so includes vying for top tournament prizes, which in the largest tournaments have exceeded one million dollars for a winning fish. Anglers who have not gained substantial expertise with circle hooks will have a diminished chance of catching a prize winning fish.

NMFS has received input from numerous anglers and tournament operators who voluntarily switched to using circle hooks prior to the existing tournament requirement who now indicate a strong preference for circle hooks over J-hooks based on

conservation benefits and who claim a lower rate of lost fish on circle hooks. Based on the economic incentives discussed above, the input from experienced billfish anglers who have acquired expertise with circle hooks, and existing studies (Prince *et al.*, 2002) indicating that hook type (circle hook vs. J-hook) is not a significant factor in catchability of Atlantic blue marlin, NMFS is confident that the concerns of anglers regarding the effectiveness of circle hooks for catching blue marlin and the resistance to using circle hooks stemming from preconceived ideas of circle hook efficacy and a lack of experience with circle hooks will be overcome if anglers are given more time to become familiar and proficient with them through an additional phase-in period. NMFS believes that in the long-term, the additional time provided to anglers to become more familiar and proficient with circle hooks may lead to higher levels of compliance with circle-hook requirements and increased use of circle hooks outside of tournaments thereby providing an increased conservation benefit for Atlantic billfish in the long-term.

NMFS estimates that there will be few or no measurable social or economic impacts resulting from the preferred alternative. However, it is possible that the temporary suspension of billfish tournament circle hook requirements may provide for a short-term increase in angler's willingness to pay based on the perception among many anglers that it is easier to catch a billfish with a J-hooks than a circle hook. Nonetheless, based in part on recent high levels of tournament registrations for 2007 occurring under circle hook requirements, NMFS does not anticipate any measurable change in billfish tournament participation, increases in purchases of fuel or dockage, or other shore-side services. Should alternative 2 result in an increased ecological benefit, there could be a long-term gain in angler's willingness to pay if billfish stocks recover and interactions with billfish increase.

NMFS does not anticipate that alternative 2 would result in additional expenditures to comply with the proposed regulations. Relative to expenditures that can quickly reach into the hundreds of thousands of dollars, or more, to purchase, equip, maintain, and fuel sportfishing vessels, hook expenditures are negligible. The FCHMS FMP identifies hook prices as ranging from $0.50 to $7.50 ($2.70 average) each for J-hooks and from $0.30 to $7.00 ($2.24 average) each for circle hooks (2006 dollars). Tournament anglers likely already possess circle hooks which have been required since January 1, 2007, and which would be required upon reinstatement of existing requirements on January 1, 2008, under the preferred alternative. Further, existing regulations allow anglers to use J-hooks on artificial lures in tournaments and do not require anglers to utilize circle hooks outside of tournaments; because of this, anglers most likely already possess J-hooks, should they choose to stop using circle hooks in tournaments. Alternative 2 does not mandate any particular terminal tackle, so anglers would be free to use any hook type, circle or J, available and which they already possess, which would further minimizing any potential compliance costs.

Alternative 3, would remove Atlantic billfish tournament circle hook requirements and promote voluntary use of circle hooks by tournament anglers, and would be expected to have minimal impacts on businesses. Minor economic impacts would be incurred by those tournaments that choose to reprint tournament rules for distribution. Alternative 3 could result in minor short-term increases in angler-consumer surplus and/or willingness to pay, as anglers may perceive that their short-term catch rates of Atlantic billfish may increase with the use of J-hooks. However, alternative 3 would not be expected to increase angler consumer surplus or willingness to pay in the long-term as it would result in an increase in post-release hooking mortality and thus be less likely to contribute to rebuilding of Atlantic billfish populations.

List of Subjects in 50 CFR Part 635

Fish, Fisheries, Fishing, Fishing vessels, Management.

Dated: March 9, 2007.

William T. Hogarth,

Assistant Administrator for Fisheries, National Marine Fisheries Service.

For reasons set out in the preamble, 50 CFR part 635 is proposed to be amended as follows:

PART 635—ATLANTIC HIGHLY MIGRATORY SPECIES

1. The authority citation for part 635 continues to read as follows:

Authority: 16 U.S.C. 971 *et seq.*; 16 U.S.C. 1801 *et seq.*

2. In § 635.21, paragraph (e)(2)(iii) is revised to read as follows:

§ 635.21 Gear operation and deployment restrictions.

* * * * *

(e)* * *

(2)* * *

(iii) After December 31, 2007, persons who have been issued or are required to be issued a permit under this part and who are participating in a ''tournament'', as defined in 635.2, that bestows points, prizes, or awards for Atlantic billfish must deploy only non-offset circle hooks when using natural bait or natural bait/artificial lure combinations, and may not deploy a J-hook or an offset circle hook in combination with natural bait or a natural bait/artificial lure combination.

* * * * *

[FR Doc. 07–1216 Filed 3–12–07; 2:43 pm]

BILLING CODE 3510–22–S

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 648

[Docket No. 061020273–7054–04; I.D. 030107B]

RIN 0648–AT60

Fisheries of the Northeastern United States; Recreational Management Measures for the Summer Flounder, Scup, and Black Sea Bass Fisheries; Fishing Year 2007

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Proposed rule; request for comments.

SUMMARY: NMFS proposes recreational management measures for the 2007 summer flounder, scup, and black sea bass fisheries. The implementing regulations for these fisheries require NMFS to publish recreational measures for the upcoming fishing year and to provide an opportunity for public comment. The intent of these measures is to prevent overfishing of the summer flounder, scup, and black sea bass resources.

DATES: Comments must be received by 5 p.m. local time, on March 30, 2007.

ADDRESSES: You may submit comments by any of the following methods:

- *E-mail: FSBrecreational2007@noaa.gov*. Include in the subject line the following identifier: ''Comments on 2007 Summer Flounder, Scup, and Black Sea Bass Recreational Measures.''
- *Federal e-rulemaking portal: http://www.regulations.gov*
- *Mail:* Patricia A. Kurkul, Regional Administrator, NMFS, Northeast

Regional Office, One Blackburn Drive, Gloucester, MA 01930. Mark the outside of the envelope: ''Comments on 2007 Summer Flounder, Scup, and Black Sea Bass Recreational Measures.

- *Fax:* (978) 281–9135

Copies of supporting documents used by the Summer Flounder, Scup, and Black Sea Bass Monitoring Committees and of the Environmental Assessment, Regulatory Impact Review, and Initial Regulatory Flexibility Analysis (EA/RIR/IRFA) are available from Daniel T. Furlong, Executive Director, Mid-Atlantic Fishery Management Council, Room 2115, Federal Building, 300 South New Street, Dover, DE 19901–6790. The EA/RIR/IRFA is also accessible via the Internet at *http://www.nero.noaa.gov*.

FOR FURTHER INFORMATION CONTACT: Michael P. Ruccio, Fishery Policy Analyst, (978) 281–9104.

SUPPLEMENTARY INFORMATION:

Background

The summer flounder, scup, and black sea bass fisheries are managed cooperatively by the Atlantic States Marine Fisheries Commission (Commission) and the Mid-Atlantic Fishery Management Council (Council), in consultation with the New England and South Atlantic Fishery Management Councils.

The management units specified in the Fishery Management Plan (FMP) for the Summer Flounder, Scup, and Black Sea Bass Fisheries include summer flounder (*Paralichthys dentatus*) in U.S. waters of the Atlantic Ocean from the southern border of North Carolina northward to the U.S./Canada border, and scup (*Stenotomus chrysops*) and black sea bass (*Centropristis striata*) in U.S. waters of the Atlantic Ocean from 35°15.3′ N. lat. (the latitude of Cape Hatteras Lighthouse, Buxton, NC) northward to the U.S./Canada border.

The FMP and its implementing regulations, which are found at 50 CFR part 648, subparts A (General Provisions), G (summer flounder), H (scup), and I (black sea bass), describe the process for specifying annual recreational measures that apply in the Exclusive Economic Zone (EEZ). The states manage these fisheries within 3 miles of their coasts, under the Commission's plan for summer flounder, scup, and black sea bass. The Federal regulations govern vessels fishing in the EEZ, as well as vessels possessing a Federal fisheries permit, regardless of where they fish.

The FMP established Monitoring Committees (Committees) for the three fisheries, consisting of representatives from the Commission; the Mid-Atlantic, New England, and South Atlantic Councils; and NMFS. The FMP and its implementing regulations require the Committees to review scientific and other relevant information annually and to recommend management measures necessary to achieve the recreational harvest limits established for the summer flounder, scup, and black sea bass fisheries for the upcoming fishing year. The FMP limits these measures to minimum fish size, possession limit, and fishing season.

The Council's Demersal Species Committee and the Commission's Summer Flounder, Scup, and Black Sea Bass Management Board (Board) then consider the Committees' recommendations and any public comment in making their recommendations to the Council and the Commission, respectively. The Council then reviews the recommendations of the Demersal Species Committee, makes its own recommendations, and forwards them to NMFS for review. The Commission similarly adopts recommendations for the states. NMFS is required to review the Council's recommendations to ensure that they are consistent with the targets specified for each species in the FMP.

Quota specifications for the 2007 summer flounder, scup, and black sea bass fisheries were published on December 14, 2006 (71 FR 75134). The summer flounder quota specification was later increased by emergency rule on January 19, 2007 (72 FR 2458), consistent with the provisions of the Magnuson-Stevens Fishery Conservation and Management Act Reauthorization of 2006. The summer flounder emergency rule will expire after 180 days, on July 18, 2007, unless extended by NMFS. NMFS intends to undertake notice and comment rulemaking in the **Federal Register** before the current emergency rule expires to extend the initial rule's measures through the fishing year ending December 31, 2007. However, should the emergency rule not be extended for any reason, the original summer flounder quota specification would become effective again and NMFS would revise the summer flounder recreational measures to be consistent with the lower recreational harvest limit. The quota specification contained in the emergency rule has been determined to be consistent with the 2007 target fishing mortality rate (F) for summer flounder. The specifications contained in the December 14, 2006, rule were determined to be consistent with the 2007 target exploitation rates for scup and black sea bass.

Based on the specifications currently in place, the 2007 coastwide recreational harvest limits are 6,844,800 lb (3,105 mt) for summer flounder, 2,744,200 lb (1,245 mt) for scup, and 2,473,500 lb (1,122 mt) for black sea bass. The specification rules did not establish recreational measures, since final recreational catch data for 2006 were not available when the Council made its recreational harvest limit recommendation to NMFS.

All minimum fish sizes discussed hereafter are total length measurements of the fish, i.e., the straight-line distance from the tip of the snout to the end of the tail while the fish is lying on its side. For black sea bass, total length measurement does not include the caudal fin tendril. All possession limits discussed below are per person.

Summer Flounder

Overall, recreational landings for 2006 were estimated to have been 11.74 million lb (5,325 mt). This exceeded, by approximately 26 percent, the 2006 recreational harvest limit of 9.29 million lb (4,214 mt). Five individual states are projected to have exceeded their 2006 state harvest limits when their allocations are converted to number of fish using the average weight of summer flounder harvested during 2005 and 2006. These states are, with their respective percent overage, as follows: MA (2 percent); RI (25 percent); NY (29 percent); NJ (9 percent); and VA (41 percent).

The 2007 coastwide harvest limit is 6,844,800 lb (3,105 mt), a 26.4–percent decrease from the 2006 harvest limit. Assuming the same level of fishing effort in 2007, a 41.7–percent reduction in landings coastwide would be required for summer flounder. The Council is recommending conservation equivalency, described as follows, that would require individual states to reduce summer flounder landings (in number of fish) to achieve the necessary recreational harvest reductions for 2007.

NMFS implemented Framework Adjustment 2 to the FMP (Framework Adjustment 2) on July 29, 2001 (66 FR 36208), which established a process that makes conservation equivalency an option for the summer flounder recreational fishery. Conservation equivalency allows each state to establish its own recreational management measures (possession limits, minimum fish size, and fishing seasons) to achieve its state harvest limit, as long as the combined effect of all of the states' management measures achieves the same level of conservation as would Federal coastwide measures developed to achieve the overall

recreational harvest limit, if implemented by all of the states.

The Council and Board recommend annually that either state-specific recreational measures be developed (conservation equivalency) or coastwide management measures be implemented by all states to ensure that the recreational harvest limit will not be exceeded. Even when the Council and Board recommend conservation equivalency, the Council must specify a set of coastwide measures that would apply if conservation equivalency is not approved. If conservation equivalency is recommended, and following confirmation that the proposed state measures would achieve conservation equivalency, NMFS may waive the permit condition found at § 648.4(b), which requires federally permitted vessels to comply with the more restrictive management measures when state and Federal measures differ. Federally permitted charter/party permit holders and recreational vessels fishing for summer flounder in the EEZ then would be subject to the recreational fishing measures implemented by the state in which they land summer flounder, rather than the coastwide measures.

In addition, the Council and the Board must recommend precautionary default measures. The Commission would require adoption of the precautionary default measures by any state that either does not submit a summer flounder management proposal to the Commission's Summer Flounder Technical Committee, or that submits measures that are determined not to achieve the required reduction. The precautionary default measures are defined as the set of measures that would achieve the greatest reduction in landings required for any state.

In December 2006, the Council and Board voted to recommend conservation equivalency to achieve the 2007 recreational harvest limit. The Commission's conservation equivalency guidelines require the states to determine and implement appropriate state-specific management measures (i.e., possession limits, fish size limits, and fishing seasons) to achieve state-specific harvest limits. Under this approach, each state may implement unique management measures appropriate to that state, so long as these measures are determined by the Commission to provide equivalent conservation as would Federal coastwide measures developed to achieve the overall recreational harvest limit. According to the conservation equivalency procedures established in Framework Adjustment 2, each state from MA to NC, excluding MD, would be required to reduce 2007 landings by the percentages shown in Table 1. MD may submit more liberal management measures, provided that they are sufficient to meet the 2007 state harvest limit. ME and NH have no recreational summer flounder harvest limit and are not required to submit management measures to the Commission.

TABLE 1. REQUIRED STATE BY STATE REDUCTIONS IN SUMMER FLOUNDER RECREATIONAL HARVEST LIMITS FOR 2007.

State	ME	NH	MA	RI	CT	NY	NJ	DE	MD	VA	NC
Percent change from 2006 to 2007	—	—	-35.3	-47.2	-13.7	-48.6	-39.5	-29.3	0.0	-53.0	-8.1

The Board required that each state submit its conservation equivalency proposal to the Commission by January 15, 2007. The Commission's Summer Flounder Technical Committee then evaluated the proposals and advised the Board of each proposal's consistency with respect to achieving the coastwide recreational harvest limit. The Commission invited public participation in its review process by allowing public comment on the state proposals at the Technical Committee meeting held on January 22, 2007. The Board met on January 31, 2007, and approved a range of management proposals for each state, as well as regional and coastwide management options designed to attain conservation equivalency. Once the states select and submit their final summer flounder management measures to the Commission, the Commission will notify NMFS as to which individual state, regional, or coastwide proposals have been approved or disapproved. NMFS retains the final authority either to approve or to disapprove using conservation equivalency in place of the coastwide measures and will publish its determination as a final rule in the **Federal Register** to establish the 2007 recreational measures for these fisheries.

States that do not submit conservation equivalency proposals, or for which proposals were disapproved by the Commission, will be required by the Commission to adopt the precautionary default measures. In the case of states that are initially assigned precautionary default measures, but subsequently receive Commission approval of revised state measures, NMFS will publish a notice in the **Federal Register** announcing a waiver of the permit condition at § 648.4(b).

As described above, for each fishing year, NMFS implements either coastwide measures or conservation equivalent measures at the final rule stage. The coastwide measures recommended by the Council and Board for 2007 are a 19–inch (48.26–cm) minimum fish size, a possession limit of one fish, and an open season from January 1 through December 31. In this action, NMFS proposes these coastwide measures in the EEZ, as they are expected to constrain landings to the overall recreational harvest. These measures would be waived if conservation equivalency is approved.

The precautionary default measures specified by the Council and Board are an 18.5–inch (46.99–cm) minimum fish size, a possession limit of one fish, and an open season of January 1 through December 31. These measures are also estimated to achieve the 2007 target if applied coastwide.

Scup

The 2007 scup recreational harvest limit is approximately 2.74 million lb (1,245 mt), a 34–percent decrease from the 2006 recreational harvest limit of 4.15 million lb (1,882 mt). Recreational landings in 2006 were estimated to have been 2.8 million lb (1,270 mt). The 2.1–percent difference in the estimated 2006 landings and 2007 target is well within the percent standard error for scup landings estimated from the Marine Recreational Fishery Statistics Survey (MRFSS). As such, no reduction from the 2006 measures would be necessary for 2007, as the status quo measures are unlikely to result in exceeding the 2007 target.

The 2007 scup recreational fishery will be managed under separate regulations for state and Federal waters; the Federal measures would apply to party/charter vessels with Federal permits and other vessels subject to the possession limit that fish in the EEZ. In Federal waters, to achieve the 2007 target, NMFS proposes to maintain the status quo coastwide management measures of a 10–inch (25.40–cm) minimum fish size, a 50–fish possession

limit, and open seasons of January 1 through February 28, and September 18 through November 30, as recommended by the Council.

As has occurred in the past 5 years, the scup fishery in state waters will be managed under a regional conservation equivalency system developed through the Commission. Addendum XI to the Interstate FMP (Addendum XI), approved by the Board at the January 2004 Council/Commission meeting, requires that the states of Massachusetts through New York each develop state-specific management measures to constrain their landings to an annual harvest level for this region in number of fish (approximately 3.1 million fish for 2007), through a combination of minimum fish size, possession limits, and seasonal closures. Because the Federal FMP does not contain provisions for conservation equivalency, and states may adopt their own unique measures under Addendum XI, the Federal and state recreational scup management measures will differ for 2007.

At the January 31, 2007, meeting, the Board approved a regional management proposal for MA through NY that would allow a season of at least 150 days. The Board retained a minimum fish size of 10.5 inches (26.7 cm) and a common possession limit (25 fish for private vessels and shore-based anglers; and 60 fish for party/charter vessels, dropping to 25 fish after a 2–month period) for the states of MA through NY. These northern states are expected to submit their final management measures to the Commission by March 1, 2007. New Jersey will maintain status quo scup recreational management measures of a 9–inch (22.9–cm) minimum size, a 50–fish possession limit, and open seasons of January 1 through February 28, and July 1 through December 31. Due to low scup landings in Delaware through North Carolina, the Board approved the retention of status quo management measures for those states as well, i.e., an 8–inch (20.3–cm) minimum fish size, a 50–fish possession limit, and no closed season.

Black Sea Bass

Recreational landings in 2007 were estimated to have been 1.91 million lb (866 mt)-- 52 percent below the 2006 target of 3.99 million lb (1,809 mt) and 23 percent below the 2007 target of 2.47 million lb (1,122 mt). The 2007 recreational harvest limit of 2.47 million lb (1,122 mt) is a 38–percent decrease from the 2006 target. Based on 2006 landings, no reduction in landings is necessary to achieve the 2007 target.

For Federal waters, the Council and Board have approved measures that would maintain the 25–fish possession limit, the 12–inch (30.48–cm) minimum size, and open season of January 1 through December 31. NMFS proposes to maintain these measures, which are expected to constrain recreational black sea bass landings to the 2007 target.

Classification

NMFS has determined that the proposed rule is consistent with the FMP and preliminarily determined that the rule is consistent with the Magnuson-Stevens Fishery Conservation and Management Act and other applicable laws.

This proposed rule has been determined to be not significant for purposes of Executive Order 12866.

An IRFA was prepared, as required by section 603 of the RFA. The IRFA describes the economic impact this proposed rule, if adopted, would have on small entities. A description of the action, why it is being considered, and the legal basis for this action are contained at the beginning of this section of the preamble and in the **SUMMARY** section of the preamble. A summary of the analysis follows. A copy of the complete IRFA is available from the Council (see **ADDRESSES**).

This proposed rule does not duplicate, overlap, or conflict with other Federal rules.

The proposed action could affect any recreational angler who fishes for summer flounder, scup, or black sea bass in the EEZ or on a party/charter vessel issued a Federal permit for summer flounder, scup, and/or black sea bass. However, the IRFA focuses upon the impacts on party/charter vessels issued a Federal permit for summer flounder, scup, and/or black sea bass because these vessels are considered small business entities for the purposes of the RFA, i.e., businesses with gross revenues of up to $3.5 million. These small entities can be specifically identified in the Federal vessel permit database and would be impacted by the recreational measures, regardless of whether they fish in Federal or state waters. Although individual recreational anglers are likely to be impacted, they are not considered small entities under the RFA. Also, there is no permit requirement to participate in these fisheries; thus, it would be difficult to quantify any impacts on recreational anglers in general.

The Council estimated that the proposed measures could affect any of the 920 vessels possessing a Federal charter/party permit for summer flounder, scup, and/or black sea bass in 2005, the most recent year for which complete permit data are available. However, only 331 of these vessels reported active participation in the recreational summer flounder, scup, and/or black sea bass fisheries in 2005.

In the IRFA, the no-action alternative (i.e., maintenance of the regulations as codified) is defined as implementation of the following: (1) for summer flounder, coastwide measures of a 17–inch (43.18–cm) minimum fish size, a 4–fish possession limit, and no closed season, i.e., the current Federal regulatory measure that would be implemented if conservation equivalency is not implemented in the final rule; (2) for scup, a 10–inch (25.40–cm) minimum fish size, a 50–fish possession limit, and open seasons of January 1 through February 28, and September 18 through November 30; and (3) for black sea bass, a 12–inch (30.48–cm) minimum size, a 25–fish possession limit, and an open season of January 1 through December 31.

The no-action alternatives for scup and black sea bass are the same (status quo) measures being proposed for 2007. Landings of these species in 2006 were either less than their respective target (black sea bass) or within the within the average observed percent standard error for the estimated landings (scup), and the status quo measures are expected to constrain landings to the 2007 targets. As such, since there is no regulatory change being proposed for these two species, there is no need of further discussion of the economic impacts within this section.

For summer flounder, state-specific implications of adopting the no-action (coastwide) alternative would result in more restrictive measures than conservation equivalent regulations in place for all Northeast (NE) states in 2006. In consideration of the recreational harvest limits established for the 2007 fishing year, taking no action in the summer flounder fishery would be inconsistent with the goals and objectives of the FMP and its implementing regulations because the no-action alternative would not be expected to prevent the 2007 summer flounder recreational harvest limits from being exceeded.

Effects of the various management measures were analyzed by employing quantitative approaches, to the extent possible. Where quantitative data were not available, the Council conducted qualitative analyses. Although NMFS's RFA guidance recommends assessing changes in profitability as a result of proposed measures, the quantitative impacts were instead evaluated using

changes in party/charter vessel revenues as a proxy for profitability. This is because reliable cost data are not available for these fisheries. Without reliable cost data, profits cannot be discriminated from gross revenues. As reliable cost data become available, impacts to profitability can be more accurately forecast. Similarly, changes to long-term solvency were not assessed due both to the absence of cost data and because the recreational management measures change annually according to the specification-setting process.

Assessments of potential changes in gross revenues for all 18 combinations of alternatives proposed in this action were conducted for federally permitted party/charter vessels in each state in the NE region. Management measures proposed under the summer flounder conservation equivalency alternative have yet to be adopted; therefore, potential losses under this alternative could not be analyzed in conjunction with alternatives proposed for scup and black sea bass. Since conservation equivalency allows each state to tailor specific recreational fishing measures to the needs of that state, while still achieving conservation goals, it is likely that the measures developed under this alternative, when considered in combination with the measures proposed for scup and black sea bass, would have fewer overall adverse effects than any of the other combinations that were analyzed.

Impacts were examined by first estimating the number of angler trips aboard party/charter vessels in each state in 2006 that would have been affected by the proposed 2007 management measures. All 2006 party/charter fishing trips that would have been constrained by the proposed 2007 measures in each state were considered to be affected trips.

There is very little information available to estimate empirically how sensitive the affected party/charter vessel anglers might be to the proposed fishing regulations. If the proposed measures discourage trip-taking behavior among some of the affected anglers, economic losses may accrue to the party/charter vessel industry in the form of reduced access fees. On the other hand, if the proposed measures do not have a negative impact on the value or satisfaction the affected anglers derive from their fishing trips, party/charter revenues would remain unaffected by this action. In an attempt to estimate the potential changes in gross revenues to the party/charter vessel industry in each state, two hypothetical scenarios were considered: A 25–percent reduction, and a 50–percent reduction, in the number of fishing trips that are predicted to be affected by implementation of the management measures in the NE (ME through NC) in 2007.

Total economic losses to party/charter vessels were then estimated by multiplying the number of potentially affected trips in each state in 2007, under the two hypothetical scenarios, by the estimated average access fee paid by party/charter anglers in the NE in 2006. Finally, total economic losses were divided by the number of federally permitted party/charter vessels that participated in the summer flounder fisheries in 2005 in each state (according to homeport state in the NE database) to obtain an estimate of the average projected gross revenue loss per party/charter vessel in 2007.

MRFSS data indicate that anglers took 36.98 million fishing trips in 2006 in the Northeastern U.S., and that party/charter anglers accounted for 5.1 percent of the angler fishing trips. The number of party/charter trips in each state ranged from approximately 29,700 in NH to approximately 510,000 in DE. The number of trips that targeted summer flounder was identified, as appropriate, for each measure, and the number of trips that would be impacted by the proposed measures was estimated. Finally, the revenue impacts were estimated by calculating the average fee paid by anglers on party/charter vessels in the NE in 2006 ($41.07 per angler), and the revenue impacts on individual vessels were estimated. The analysis assumed that angler effort and catch rates in 2007 will be similar to 2006.

The Council noted that this method is likely to result in overestimation of the potential revenue losses that would result from implementation of the proposed coastwide measures in these three fisheries for several reasons. First, the analysis likely overestimates the potential revenue impacts of these measures because some anglers would continue to take party/charter vessel trips, even if the restrictions limit their landings. Also, some anglers may engage in catch and release fishing and/or target other species. It was not possible to estimate the sensitivity of anglers to specific management measures. Second, the universe of party/charter vessels that participate in the fisheries is likely to be even larger than presented in these analyses, as party/charter vessels that do not possess a Federal summer flounder, scup, or black sea bass permit because they fish only in state waters are not represented in the analyses. Considering the large proportion of landings from state waters (e.g., more than 81 percent of summer flounder landings in 2005), it is probable that some party/charter vessels fish only in state waters and, thus, do not hold Federal permits for these fisheries. Third, vessels that hold only state permits likely will be fishing under different, potentially less restrictive, recreational measures for summer flounder in state waters, if such program is implemented in the final rule.

Impacts of Summer Flounder Alternatives

The proposed action for the summer flounder recreational fishery would limit coastwide catch to approximately 6.84 million lb (3,105 mt) by imposing coastwide Federal measures throughout the EEZ. As described earlier, upon confirmation that the proposed state measures would achieve conservation equivalency, NMFS may waive the permit condition found at § 648.4(b), which requires federally permitted vessels to comply with the more restrictive management measures when state and Federal measures differ. Federally permitted charter/party permit holders and recreational vessels fishing for summer flounder in the EEZ then would be subject to the recreational fishing measures implemented by the state in which they land summer flounder, rather than the coastwide measures.

The impact of the proposed summer flounder conservation equivalency alternative (in Summer Flounder Alternative 1) among states is likely to be similar to the level of landings reductions that are required of each state. As indicated above, each state except MD would be required to reduce summer flounder landings in 2007, relative to state 2006 landings, by the percentages shown in Table 1 of the preamble of this proposed rule. If the preferred conservation equivalency alternative is effective at achieving the recreational harvest limit, then it is likely to be the only alternative that minimizes adverse economic impacts, to the extent practicable, yet achieves the biological objectives of the FMP. Because states have a choice, it is expected that the states would adopt conservation equivalent measures that result in fewer adverse economic impacts than the much more restrictive precautionary default measures (i.e., only one fish measuring at least 18.5 inches (46.99 cm)). Under the precautionary default measures, impacted trips are defined as trips taken in 2006 that landed at least one summer flounder smaller than 18.5 inches (46.99 cm) or landed more than one summer flounder. The analysis concluded that

implementation of precautionary default measures could affect 4.06 percent of the party/charter vessel trips in the NE, including those trips were no summer flounder were caught.

The impacts of the proposed summer flounder coastwide alternative (Summer Flounder Alternative 2), i.e., a 19–inch (48.26–cm) minimum fish size, a one-fish possession limit, and no closed season, were evaluated using the quantitative method described above. Impacted trips were defined as individual angler trips taken aboard party/charter vessels in 2006 that landed at least one summer flounder smaller than 19 inches (48.26 cm), or that landed more than one summer flounder. The analysis concluded that the measures would affect 4.13 percent of the party/charter vessel trips in the NE, including those trips where no summer flounder were caught.

Combined Impacts of Summer Flounder, Scup, and Black Sea Bass Alternatives

Since the management measures under Summer Flounder Alternative 1 (i.e., conservation equivalency) have yet to be adopted, the effort effects of this alternative could not be analyzed in conjunction with the alternatives proposed for scup and black sea bass. The percent of total party/charter boat trips in the NE that are estimated to be affected by the proposed actions ranges from a low of 6.24 percent for the combination of measures proposed under the summer flounder precautionary default, scup alternative 1, and black sea bass alternative 2, to 7.30 percent for the measures proposed under summer flounder alternative 2 combined with scup alternative 2 and black sea bass alternative 3.

Regionally, party/charter revenue losses in 2007 from $4.392 million to $3.753 million in sales, $1.370 million to $1.588 million in income, and between 37 and 43 jobs if a 25–percent reduction in the number of affected trips occurs. The estimated losses are approximately twice as high if a 50–percent reduction in affected trips is assumed to occur.

Potential revenue losses in 2007 could differ for party/charter vessels that land more than one of the regulated species. The cumulative maximum gross revenue loss per vessel varies by the combination of permits held and by state. All 18 potential combinations of management alternatives for summer flounder, scup, and black sea bass are predicted to affect party/charter vessel revenues to some extent in all of the Northeastern coastal states. Although potential losses were estimated for party/charter vessels operating out of Maine and New Hampshire, these results are suppressed for confidentiality purposes. Average party/charter losses for federally permitted vessels operating in the remaining states are estimated to vary across the 18 combinations of alternatives. For example, in New York, average losses are predicted to range from $4,834 per vessel under the combined effects of summer flounder precautionary default measures (considered under alternative 1), scup alternative 1, and black sea bass alternative 2 management measures, to $6,122 per vessel under the combined effects of summer flounder alternative 2, scup alternative 2, and black sea bass alternative 3 management measures, assuming a 25–percent reduction in effort, as described above.

There are no new reporting or recordkeeping requirements contained in any of the alternatives considered for this action.

Dated: March 9, 2007.

William T. Hogarth,

Assistant Administrator for Fisheries, National Marine Fisheries Service.

For the reasons set out in the preamble, 50 CFR part 648 is proposed to be amended as follows:

PART 648—FISHERIES OF THE NORTHEASTERN UNITED STATES

1. The authority citation for part 648 continues to read as follows:

Authority: 16 U.S.C. 1801 *et seq.*

2. In § 648.103, paragraph (b) is revised to read as follows:

§ 648.103 Minimum fish sizes.

* * * * *

(b) Unless otherwise specified pursuant to § 648.107, the minimum size for summer flounder is 19 inches (48.26 cm) TL for all vessels that do not qualify for a moratorium permit, and charter boats holding a moratorium permit if fishing with more than three crew members, or party boats holding a moratorium permit if fishing with passengers for hire or carrying more than five crew members.

* * * * *

3. In § 648.105, the first sentence of paragraph (a) is revised to read as follows:

§ 648.105 Possession restrictions.

* * * * *

(a) Unless otherwise specified pursuant to § 648.107, no person shall possess more than one summer flounder in, or harvested from, the EEZ, unless that person is the owner or operator of a fishing vessel issued a summer flounder moratorium permit, or is issued a summer flounder dealer permit. * * *

* * * * *

4. In § 648.107, paragraph introductory text (a) and paragraph (b) are revised to read as follows:

§ 648.107 Conservation equivalent measures for the summer flounder fishery.

(a) The Regional Administrator has determined that the recreational fishing measures proposed to be implemented by Massachusetts through North Carolina for 2007 are the conservation equivalent of the season, minimum fish size, and possession limit prescribed in §§ 648.102, 648.103, and 648.105(a), respectively. This determination is based on a recommendation from the Summer Flounder Board of the Atlantic States Marine Fisheries Commission.

* * * * *

(b) Federally permitted vessels subject to the recreational fishing measures of this part, and other recreational fishing vessels subject to the recreational fishing measures of this part and registered in states whose fishery management measures are not determined by the Regional Administrator to be the conservation equivalent of the season, minimum size, and possession limit prescribed in §§ 648.102, 648.103(b) and 648.105(a), respectively, due to the lack of, or the reversal of, a conservation equivalent recommendation from the Summer Flounder Board of the Atlantic States Marine Fisheries Commission, shall be subject to the following precautionary default measures: Season - January 1 through December 31; minimum size - 18.5 inches (46.99 cm); and possession limit – one fish.

[FR Doc. E7–4780 Filed 3–14–07; 8:45 am]

BILLING CODE 3510–22–S

Notices

Federal Register
Vol. 72, No. 50
Thursday, March 15, 2007

This section of the FEDERAL REGISTER contains documents other than rules or proposed rules that are applicable to the public. Notices of hearings and investigations, committee meetings, agency decisions and rulings, delegations of authority, filing of petitions and applications and agency statements of organization and functions are examples of documents appearing in this section.

DEPARTMENT OF AGRICULTURE

Agricultural Research Service

Notice of Intent to Grant Exclusive License

AGENCY: Agricultural Research Service, USDA.

ACTION: Notice of intent.

SUMMARY: Notice is hereby given that the U.S. Department of Agriculture, Agricultural Research Service, intends to grant to Caribbean Dairy Institute, Inc. of Mayagüez, Puerto Rico, an exclusive license to U.S. Patent Application Serial No. 10/895,797, ''Methods for Prevention and Treatment of Mastitis'', filed on July 21, 2004.

DATES: Comments must be received within thirty (30) days of the date of publication of this Notice in the **Federal Register**.

ADDRESSES: Send comments to: USDA, ARS, Office of Technology Transfer, 5601 Sunnyside Avenue, Room 4–1174, Beltsville, Maryland 20705–5131.

FOR FURTHER INFORMATION CONTACT: June Blalock of the Office of Technology Transfer at the Beltsville address given above; telephone: 301–504–5989.

SUPPLEMENTARY INFORMATION: The Federal Government's patent rights to this invention are assigned to the United States of America, as represented by the Secretary of Agriculture. It is in the public interest to so license this invention as Caribbean Dairy Institute, Inc. of Mayagüez, Puerto Rico has submitted a complete and sufficient application for a license. The prospective exclusive license will be royalty-bearing and will comply with the terms and conditions of 35 U.S.C. 209 and 37 CFR 404.7. The prospective exclusive license may be granted unless, within thirty (30) days from the date of this published Notice, the Agricultural Research Service receives written evidence and argument which establishes that the grant of the license would not be consistent with the requirements of 35 U.S.C. 209 and 37 CFR 404.7.

Richard J. Brenner,
Assistant Administrator.

[FR Doc. E7–4709 Filed 3–14–07; 8:45 am]

BILLING CODE 3410–03–P

DEPARTMENT OF COMMERCE

Submission for OMB Review; Comment Request

The Department of Commerce will submit to the Office of Management and Budget (OMB) for clearance the following proposal for collection of information under the provisions of the Paperwork Reduction Act (44 U.S.C. chapter 35).

Agency: U.S. Census Bureau.

Title: 2008 Census Coverage Measurement, Independent Listing and Relisting Operations.

Form Number(s): DX–1302.

Agency Approval Number: None.

Type of Request: New collection.

Burden: 1,559 hours.

Number of Respondents: 40,000.

Average Hours Per Response: 2 minutes.

Needs and Uses: In preparation for the 2010 Census, the U.S. Census Bureau requests authorization from OMB to conduct the Census Coverage Measurement (CCM) Independent Listing Interview and the CCM Relisting Interview as part of the 2008 Dress Rehearsal. The CCM program for the dress rehearsal is designed to test that all planned coverage measurement operations are working as expected, that they are integrated internally, and that they are coordinated with the appropriate census operations.

The 2008 Census Dress Rehearsal will be conducted in two sites, one urban, and the other one, a mix of urban and suburban. San Joaquin County, California is the urban site. South Central North Carolina has been selected as the urban/suburban mix test site. This area consists of Fayetteville and nine counties surrounding Fayetteville (Chatham, Cumberland, Harnett, Hoke, Lee, Montgomery, Moore, Richmond, and Scotland).

The 2008 CCM test will be comprised of two samples selected to measure census coverage of housing units and the household population: The population sample (P sample) and the enumeration sample (E sample). The P sample is a sample of housing units and persons obtained independently from the census for a sample of block clusters. The E sample is a sample of census housing units and enumerations in the same block cluster as the P sample. The independent roster of housing units is obtained during the CCM Independent Listing, the results of which will be matched to census housing units in the sample block clusters, surrounding blocks, and across the entire site. Separate OMB packages will be submitted for subsequent CCM field operations.

The CCM operations planned for the dress rehearsal, to the extent possible, will mirror those that will be conducted for the 2010 Census to provide estimates of net coverage error and components of coverage error (omissions and erroneous enumerations) for housing units and persons in housing units (see Definition of Terms). The data collection and matching methodologies for previous coverage measurement programs were designed only to measure net coverage error, which reflects the difference between omissions and erroneous inclusions.

The Independent Listing Operation is the first step in the CCM process. It will be conducted to obtain a complete inventory of all housing unit addresses within the CCM sample block clusters before the 2008 Census Dress Rehearsal enumeration commences. In both dress rehearsal sites, Listers will canvass every street, road, or other place where people might live in their assigned block clusters and construct a list of housing units. Listers will contact a member of each housing unit (or proxy, as a last resort) to ensure all units at a given address are identified. They will also identify the location of each housing unit by assigning map spots on block cluster maps provided with their assignment materials. If an enumerator is uncertain whether particular living quarters is a housing unit, it will be listed and flagged for possible followup, if still unresolved after matching (this will be a part of the Initial Housing Unit Followup).

Completed Independent Listing Books are subject to Dependent Quality Control (DQC) wherein DQC listers return to the field to check 12 housing units per cluster to ensure that the work

performed is of acceptable quality and to verify that the correct blocks were visited. If the cluster fails the DQC, then the DQC lister reworks the entire cluster. The completed listing books are keyed for matching against the census Decennial Master Address File for the same areas.

The Independent Listing results will be computer and clerically matched to the Decennial Master Address File from the census in the same areas. As the result of the matching, an additional relisting operation can occur for block clusters having high levels of geocoding errors in the original Independent Listing. The methods and procedures for Relisting will be the same as those for the Independent Listing operation. There will be one Independent Listing Form, DX–1302, that will be used for Independent Listing, DQC, and Relisting.

Definition of Terms

Components of Coverage Error—The two components of census coverage error are census omissions (missed persons or housing units) and erroneous inclusions (persons or housing units enumerated in the census that should not have been). Examples of erroneous inclusions are: housing units built after Census Day and persons or housing units enumerated more than once (duplicates).

Net Coverage Error—Reflects the difference between census omissions and erroneous inclusions. A positive net error indicates an undercount, while a negative net error indicates an overcount.

Affected Public: Individuals or households.

Frequency: One-time.

Respondent's Obligation: Mandatory.

Legal Authority: Title 13 U.S.C. 141 & 193.

OMB Desk Officer: Brian Harris-Kojetin, (202) 395–7314.

Copies of the above information collection proposal can be obtained by calling or writing Diana Hynek, Departmental Paperwork Clearance Officer, (202) 482–0266, Department of Commerce, room 6625, 14th and Constitution Avenue, NW., Washington, DC 20230 (or via the Internet at *dHynek@doc.gov*).

Written comments and recommendations for the proposed information collection should be sent within 30 days of publication of this notice to Brian Harris-Kojetin, OMB Desk Officer either by fax (202–395–7245) or e-mail (*bharrisk@omb.eop.gov*).

Dated: March 9, 2007.

Gwellnar Banks,

Management Analyst, Office of the Chief Information Officer.

[FR Doc. E7–4705 Filed 3–14–07; 8:45 am]

BILLING CODE 3510–07–P

DEPARTMENT OF COMMERCE

Submission for OMB Review; Comment Request

The Department of Commerce will submit to the Office of Management and Budget (OMB) for clearance the following proposal for collection of information under the provisions of the Paperwork Reduction Act (44 U.S.C. Chapter 35).

Agency: National Oceanic and Atmospheric Administration (NOAA).

Title: Professional Development Workshops and Formal Evaluation of NOAA Online Education Materials.

Form Number(s): None.

OMB Approval Number: None.

Type of Request: Regular submission.

Burden Hours: 855.

Number of Respondents: 1,560.

Average Hours Per Response: Pre-workshop evaluations and student pre- and post-lesson evaluations, 15 minutes; post-workshop evaluations, 30 minutes; teacher follow-up evaluations, 1 hour.

Needs and Uses: The project has three primary goals: (1) To provide a series of three one-day professional development opportunities whereby educators will learn more about coastal and ocean science, and about the wide variety of online tools and resources available to them via the NOAA Discovery Center and Ocean Explorer Web sites; (2) To develop and implement an outcomes-based evaluation of the three educator professional development workshops; and (3) To implement an outcomes-based evaluation of the online tools and resources available through the NOAA Discovery Center and Ocean Explorer Web sites.

Affected Public: Individuals and households.

Frequency: One-time only.

Respondent's Obligation: Voluntary.

OMB Desk Officer: David Rostker, (202) 395–3897.

Copies of the above information collection proposal can be obtained by calling or writing Diana Hynek, Departmental Paperwork Clearance Officer, (202) 482–0266, Department of Commerce, Room 6625, 14th and Constitution Avenue, NW., Washington, DC 20230 (or via the Internet at *dHynek@doc.gov*).

Written comments and recommendations for the proposed information collection should be sent within 30 days of publication of this notice to David Rostker, OMB Desk Officer, FAX number (202) 395–7285, or *David_Rostker@omb.eop.gov*.

Dated: March 9, 2007.

Gwellnar Banks,

Management Analyst, Office of the Chief Information Officer.

[FR Doc. E7–4706 Filed 3–14–07; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

Submission for OMB Review; Comment Request

The Department of Commerce will submit to the Office of Management and Budget (OMB) for clearance the following proposal for collection of information under the provisions of the Paperwork Reduction Act (44 U.S.C. Chapter 35).

Agency: National Oceanic and Atmospheric Administration (NOAA).

Title: NOAA Teacher-At-Sea Program.

Form Number(s): None.

OMB Approval Number: 0648–0283.

Type of Request: Regular submission.

Burden Hours: 309.

Number of Respondents: 375.

Average Hours Per Response: Application, 1 hour; health services questionnaire, 15 minutes; and recommendation, 15 minutes.

Needs and Uses: The NOAA Teacher-at-Sea Program provides educators with the opportunity to participate in research projects aboard NOAA vessels. The respondents are educators who provide information about themselves and their teaching situation and who submit a follow-up report with ideas for classroom applications. Recommendations are also required.

Affected Public: Individuals or households.

Frequency: On occasion.

Respondent's Obligation: Required to obtain or retain benefits.

OMB Desk Officer: David Rostker, (202) 395–3897.

Copies of the above information collection proposal can be obtained by calling or writing Diana Hynek, Departmental Paperwork Clearance Officer, (202) 482–0266, Department of Commerce, Room 6625, 14th and Constitution Avenue, NW., Washington, DC 20230 (or via the Internet at *dHynek@doc.gov*).

Written comments and recommendations for the proposed information collection should be sent within 30 days of publication of this notice to David Rostker, OMB Desk Officer, FAX number (202) 395–7285, or *David_Rostker@omb.eop.gov*.

Dated: March 9, 2007.

Gwellnar Banks,

Management Analyst, Office of the Chief Information Officer.

[FR Doc. E7–4708 Filed 3–14–07; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

International Trade Administration

Implementation of Tariff Rate Quota Established Under Title V of the Trade and Development Act of 2000 as Amended by the Trade Act of 2002, the Miscellaneous Trade Act of 2004, and the Pension Protection Act of 2006, for Imports of Certain Worsted Wool; Proposed Collection Extension; Comment Request

SUMMARY: The Department of Commerce, as part of its continuing effort to reduce paperwork and respondent burdens, invites the general public and other Federal agencies to take this opportunity to comment on the continuing information collections, as required by the Paperwork Reduction Act of 1995, Public Law 104–13 (44 U.S.C. 35068 (2)(A)).

DATES: Written comments must be submitted on or before May 14, 2007.

ADDRESSES: Direct all written comments to Diana Hynek, Departmental Paperwork Clearance Officer, Department of Commerce, Room 6625, 14th & Constitution Avenue, NW., Washington, DC 20230 or via the Internet at *dHynek@doc.gov*.

FOR FURTHER INFORMATION CONTACT: Request for additional information or copies of the information collection instrument and instructions should be directed to: Sergio Botero, Trade Development, Room 3119, 14th & Constitution Avenue, NW., Washington, DC 20230; Phone number: (202) 482–4058 and fax number: (202) 482–0667.

SUPPLEMENTARY INFORMATION:

I. Abstract

Title V of the Trade and Development Act of 2000 (''the Act'') as amended by the Trade Act of 2002, the Miscellaneous Trade Act of 2004, and the Pension Protection Act of 2006 contains several provisions to assist the wool products industries. These include the establishment of tariff rate quotas (TRQ) for a limited quantity of worsted wool fabrics. The Act requires the President to fairly allocate the TRQ to persons who cut and sew men's and boys' worsted wool suits and suit like jackets and trousers in the United States, and who apply for an allocation based on the amount of suits they produce in the prior year. The Act specifies factors to be addressed in considering such requests. The TRQ was originally effective for goods entered or withdrawn from warehouse for consumption, on or after January 1, 2001, and was to remain in force through 2003. On August 6, 2002, President Bush signed into law the Trade Act of 2002, which includes several amendments to Title V of the Act including the extension of the program through 2005. On December 3, 2004, the Act was further amended pursuant to the Miscellaneous Trade Act of 2004, Public Law 108–429, by increasing the TRQ for worsted wool fabric with average fiber diameters greater than 18.5 microns, HTS 9902.51.11, to an annual total level of 5.5 million square meters, and extending it through 2007, and increasing the TRQ for average fiber diameters of 18.5 microns or less, HTS 9902.51.15 (previously 9902.51.12), to an annual total level of 5 million square meters and extending it through 2006. On August 17, 2006, the Act was further amended pursuant to the Pension Protection Act of 2006, Public Law 109–280, which extended both TRQs, 9902.51.11 and 9902.51.15, through 2009. A TRQ allocation will be valid only in the year for which it is issued.

On December 1, 2000, the President issued Proclamation 7383 that, among other things, delegates authority to the Secretary of Commerce to allocate the TRQ and to issue regulations to implement these provisions. On January 22, 2001, the Department of Commerce published regulations establishing procedures for allocation of the tariff rate quotas (66 FR 6459, 15 CFR part 335). These interim regulations were adopted, without change, as a final rule published on October 24, 2005 (70 FR 61363). The Department must collect certain information in order to fairly allocate the TRQ to eligible persons.

II. Method of Collection

The information collection forms will be provided via the Internet and by mail to requesting firms.

III. Data

OMB Number: 0625–0240.

Form Number: ITA–4139, and ITA–4140P.

Type of Review: Regular submission.

Affected Public: Business or other for-profit organizations.

Estimated Number of Respondents: 20.

Estimated Time Per Response: 1–3 hours.

Estimated Total Annual Burden Hours: 160 hours.

Estimated Total Annual Costs: $47,400.

The estimated annual cost for this collection is $47,400 ($5,400 for respondents and $42,000 for Federal Government).

IV. Request for Comments

Comments are invited on (a) Whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden (including hours and costs) of the proposed collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; and (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or forms of information technology.

Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval of this information collection; they also will become a matter of public record.

Dated: March 9, 2007.

Gwellnar Banks,

Management Analyst, Office of the Chief Information Officer.

[FR Doc. E7–4707 Filed 3–14–07; 8:45 am]

BILLING CODE 3510–DR–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

[I.D. 030807B]

New England Fishery Management Council; Public Meeting

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice of a public meeting.

SUMMARY: The New England Fishery Management Council (Council) is scheduling a public meetings of its Standardized Bycatch Reporting Methodology (SBRM) Committee in April, 2007, to consider actions affecting New England fisheries in the exclusive economic zone (EEZ). Recommendations from this group will be brought to the full Council for formal consideration and action, if appropriate.

DATES: The meeting will be held on Monday, April 9, 2007, at 1 p.m.

ADDRESSES: The meeting will be held at the Hilton Mystic Hotel, 20 Coogan

Boulevard, Mystic, CT 06355; telephone: (860) 572–0731.

Council address: New England Fishery Management Council, 50 Water Street, Mill 2, Newburyport, MA 01950.

FOR FURTHER INFORMATION CONTACT: Paul J. Howard, Executive Director, New England Fishery Management Council; telephone: (978) 465–0492.

SUPPLEMENTARY INFORMATION: The committee will meet to further consider and develop all the alternatives under consideration for the SBRM amendment.

Although non-emergency issues not contained in this agenda may come before this group for discussion, those issues may not be the subject of formal action during this meeting. Action will be restricted to those issues specifically listed in this notice and any issues arising after publication of this notice that require emergency action under section 305(c) of the Magnuson-Stevens Fishery Conservation and Management Act, provided the public has been notified of the Council's intent to take final action to address the emergency.

Special Accommodations

This meeting is physically accessible to people with disabilities. Requests for sign language interpretation or other auxiliary aids should be directed to Paul J. Howard, Executive Director, at (978) 465–0492, at least 5 days prior to the meeting date.

Authority: 16 U.S.C. 1801 *et seq.*

Dated: March 9, 2007.

Tracey L. Thompson,

Acting Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. E7–4703 Filed 3–14–07; 8:45 am]

BILLING CODE 3510–22–S

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

[I.D. 030807D]

New England Fishery Management Council; Public Meeting

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice of a public meeting.

SUMMARY: The New England Fishery Management Council's (Council) Vessel Monitoring Systems (VMS)/Enforcement Committee will meet to consider actions affecting New England fisheries in the exclusive economic zone (EEZ).

DATES: The meeting will be held on Monday, April 9, 2007, at 1 p.m.

ADDRESSES: The meeting will be held at the Hilton Mystic, 20 Coogan Boulevard, Mystic, CT 06355; telephone: (860) 572–0731.

Council address: New England Fishery Management Council, 50 Water Street, Mill 2, Newburyport, MA 01950.

FOR FURTHER INFORMATION CONTACT: Paul J. Howard, Executive Director, New England Fishery Management Council; telephone: (978) 465–0492.

SUPPLEMENTARY INFORMATION: The items of discussion in the committee's agenda are as follows:

1. Introduction: safety, regulation compliance, and familiarizing industry with proper use of VMS.
2. Presentation by Office for Law Enforcement: the capabilities and limitations of VMS as an enforcement tool.
3. Comments and recommendations from the public, VMS users, state agencies, and the Coast Guard. The committee has received the following requests:
   a. Safe harbor notification, to suspend fishing trip, due to storms or other emergencies;
   b. Produce a laminated sheet of emergency contacts;
   c. Declaration in/out of a fishery while at sea, rather than in port;
   d. Change polling frequency, to be based on fishery declaration;
   e. Closed area transit notification, to replace gear stowage requirement;
   f. Completion of the days-at-sea (DAS) web page by NMFS;
   g. Inform fishermen of existing safety features on their VMS units, by vendors;.
4. Industry and law enforcement dialog on VMS usage, and how it can be improved; and
5. Other business.

Although non-emergency issues not contained in this agenda may come before this group for discussion, those issues may not be the subject of formal action during this meeting. Action will be restricted to those issues specifically identified in this notice and any issues arising after publication of this notice that require emergency action under section 305(c) of the Magnuson-Stevens Fishery Conservation and Management Act, provided the public has been notified of the Council's intent to take final action to address the emergency.

Special Accommodations

This meeting is physically accessible to people with disabilities. Requests for sign language interpretation or other auxiliary aids should be directed to Paul J. Howard (see **ADDRESSES**) at least 5 days prior to the meeting date.

Authority: 16 U.S.C. 1801 *et seq.*

Dated: March 9, 2007.

Tracey L. Thompson,

Acting Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. E7–4704 Filed 3–14–07; 8:45 am]

BILLING CODE 3510–22–S

DEPARTMENT OF DEFENSE

Office of the Secretary

Notice of Availability of the Draft Programmatic Environmental Impact Statement for DTRA Activities on White Sands Missile Range, New Mexico

AGENCY: Department of Defense, Office of the Under Secretary of Defense for Acquisition, Technology, and Logistics, Defense Threat Reduction Agency.

ACTION: Notice of availability of final programmatic environmental impact statement (PEIS) for increased testing activities at White Sands Missile Range (WSMR), NM.

SUMMARY: Pursuant to the National Environmental Policy Act of 1969, as amended (NEPA) (42 U.S.C. 4321 *et seq.*) and the Council on Environmental Quality Regulations for Implementing the Procedural Provisions of NEPA (40 CFR Parts 1500–1508), DTRA has prepared and issued a final PEIS for the proposed testing activities at WSMR. The PEIS addresses the potential environmental impacts associated with implementing the proposed action, alternative, and no action alternative over a 10 year period. The purpose of the proposed action is to provide adequate test areas and facilities to evaluate the lethality effectiveness of weapon systems used against simulated enemy ground targets producing, storing, or controlling Weapons of Mass Destruction (WMD). There is a need to improve weapon systems designed to defeat enemy military assets including hardened and reinforced structures. These enemy military assets can house WMD and pose a significant threat to international stability and peaceful coexistence among nations. The military structures and equipment of the United States and its allies must also be refined to better withstand attack by enemy weapons systems to reduce collateral damage. The PEIS presents descriptions of the proposed action, an overview of the affected environment at and near the test sites, and the potential environmental consequences associated

with the proposed action and alternatives, including the no action alternative.

The final PEIS evaluates two alternatives in addition to the no action alternative. The proposed action (alternative 1, DTRA's Preferred Alternative) involves expanding existing test beds and creating new ones; expanding the range of test types including targets, simulants, delivery systems and explosives; implementing infrastructure improvements at the Permanent High Explosive Test Site Administrative Park; and testing special weapons and delivery systems.

Alternative two contains all of the actions described in alternative one plus the use of chemical simulants and taggants/tracers that are considered to have higher toxicity levels than those considered under alternative one. The increased hazards of using these chemicals lead to identifying alternative one as the preferred alternative.

DATES: *Effective Dates:* DTRA will take no final action on the proposed activities before April 15, 2007 or April 16, 2007. After April 15, 2007, DTRA will issue a Record of Decision (ROD). This ROD will document the Agency's final determinations, in light of the PEIS, with regard to its intended activities at WSMR. A NoA will be published in the **Federal Register** announcing the ROD's availability for public viewing.

ADDRESSES: The final PEIS is available for public viewing on the DTRA Web site, *http://www.dtra.mil,* and at the following public libraries: Albuquerque Public Library, 501 Copper Ave. Northwest, Albuquerque, NM; Socorro Public Library, 401 Park Street, Socorro, NM; Alamogordo Public Library, 920 Oregon Ave., Alamogordo, NM; Branigan Memorial Library, 200 East Picacho Ave., Law Cruces, NM; Consolidated Library Building 464, White Sands Missile Range, NM; Holloman Air Force Base Library, 596 4th Street, Holloman Air Force Base, NM; and the El Paso Public Library, 501 North Oregon Street, El Paso, TX.

FOR FURTHER INFORMATION CONTACT: DTRA Public Affairs Office; (800) 701–5096 or (703) 767–5870.

SUPPLEMENTARY INFORMATION: A draft PEIS was published in the **Federal Register** on January 27, 2006 (71 FR 4571) for a 60-day public review and comment period that ended March 28, 2006. Public hearings were held February 28, 2006 in Alamogordo, March 1, 2006 in Las Cruces, and March 2, 2006 in Socorro, NM. All comments received were addressed and incorporated into the final PEIS.

Dated: March 9, 2007.

L.M. Bynum,

Alternate OSD Federal Register Liaison Officer, DoD.

[FR Doc. 07–1214 Filed 3–14–07; 8:45 am]

BILLING CODE 5001–06–M

DEPARTMENT OF ENERGY

Environmental Management Site-Specific Advisory Board Chairs Meeting

AGENCY: Department of Energy.

ACTION: Notice of open meeting.

SUMMARY: This notice announces a meeting of the Environmental Management Site-Specific Advisory Board (EM SSAB) Chairs. The Federal Advisory Committee Act (Pub. L. 92–463, 86 Stat. 770) requires that public notice of this meeting be announced in the **Federal Register**.

DATES: Thursday, March 29, 2007, 8 a.m.–4:30 p.m.

Friday, March 30, 2007, 8 a.m.–12 p.m.

ADDRESSES: Suncoast Hotel & Casino, 9090 Alta Drive, Las Vegas, NV 89145, (702) 636–7111 or 1–877–677–7111.

FOR FURTHER INFORMATION CONTACT: E. Douglas Frost, Designated Federal Officer, U.S. Department of Energy, 1000 Independence Avenue, SW., Washington, DC 20585, (202) 586–5619.

SUPPLEMENTARY INFORMATION:

Purpose of the Board: The purpose of the EM SSAB is to make recommendations to DOE in the areas of environmental restoration, waste management, and related activities.

Tentative Agenda

Thursday, March 29, 2007

8 a.m. Welcome/Introductions
8:30 a.m. Round Robin: Top Three Issues—Each Chair
9:30 a.m. Presentation by Assistant Secretary James Rispoli
10:15 a.m. Discussion of the Federal Advisory Committee Act
12 p.m Lunch
1:30 p.m. Office of Engineering & Technology Presentation
3 p.m. Break
3:15 p.m. EM SSAB Discussion
4:15 p.m. Wrap-Up

Friday, March 30, 2007

8:30 a.m. Presentation by Environmental Management Advisory Board Vice Chair
9 a.m. Update/Discussion: Remote-Handled Transuranic Waste
10 a.m. EM SSAB Wrap-Up
11 a.m. Closing Remarks
12 p.m. Adjourn

Public Participation: The meeting is open to the public. Written statements may be filed either before or after the meeting with the Designated Federal Officer, E. Douglas Frost, at the address above or by phone at (202) 586–5619. Individuals who wish to make oral statements pertaining to agenda items should also contact E. Douglas Frost. Requests must be received five days prior to the meeting and reasonable provision will be made to include the presentation in the agenda. The Designated Federal Officer is empowered to conduct the meeting in a fashion that will facilitate the orderly conduct of business. Individuals wishing to make public comment will be provided a maximum of five minutes to present their comments.

Minutes: Minutes of this meeting will be available for public review and copying at the U.S. Department of Energy Freedom of Information Public Reading Room, 1E–190, Forrestal Building, 1000 Independence Avenue, SW., Washington, DC 20585 between 9 a.m. and 4.p.m., Monday–Friday except Federal holidays. Minutes will also be available by calling E. Douglas Frost at (202) 586–5619 and will be posted at *http://www.em.doe.gov/stakepages/ssabchairs.aspx.*

Issued at Washington, DC on March 9, 2007.

Rachel M. Samuel,

Deputy Advisory Committee Management Officer.

[FR Doc. E7–4757 Filed 3–14–07; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Office of Fossil Energy

Methane Hydrate Advisory Committee

AGENCY: Department of Energy.

ACTION: Notice of open meeting.

SUMMARY: This notice announces a meeting of the Methane Hydrate Advisory Committee. Federal Advisory Committee Act (Public Law 92–463, 86 Stat. 770) requires that notice of these meetings be announced in the **Federal Register**.

DATES: Tuesday, April 24, 2007, 8:30 a.m. to 5:30 p.m., and Wednesday, April 25, 2007, 8 a.m. to 12:30 p.m.

ADDRESSES: Table Mountain Inn, 1310 Washington Avenue, Golden, Colorado 80401.

FOR FURTHER INFORMATION CONTACT: Edith Allison, U.S. Department of Energy, Office of Oil and Natural Gas,

Washington, DC 20585. Phone: 202–586–1023.

SUPPLEMENTARY INFORMATION:

Purpose of the Committee: The purpose of the Methane Hydrate Advisory Committee is to provide advice on potential applications of methane hydrate to the Secretary of Energy, and assist in developing recommendations and priorities for the Department of Energy Methane Hydrate Research and Development Program.

Tentative Agenda

Tuesday, April 24

- Report and discussion of meeting with Deputy Secretary of Energy and congressional committees.
- Reports and discussion of key Department of Energy-supported field projects.
- Report and discussion of code comparison for various reservoir simulators.
- Report and discussion of University of Mississippi seafloor observatory.
- Report and discussion of International activities.
- Final critique of 5-year plan and preparation of 2007 report to Congress.

Wednesday, April 25

- Continue preparation of report to Congress.
- Fast Track, Environmental and International Subcommittee discussions.
- Wrap-up and discussion of action items.
- Adjourn.

Public Participation: The meeting is open to the public. The Chairman of the Committee will conduct the meeting to facilitate the orderly conduct of business. If you would like to file a written statement with the Committee, you may do so either before or after the meeting. If you would like to make oral statements regarding any of the items on the agenda, you should contact Edith Allison at the address or telephone number listed above. You must make your request for an oral statement at least five business days prior to the meeting, and reasonable provisions will be made to include the presentation on the agenda. Public comment will follow the 10-minute rule.

Minutes: The minutes of this meeting will be available for public review and copying within 60 days at the Freedom of Information Public Reading Room, Room 1E–190, Forrestal Building, 1000 Independence Avenue, SW., Washington, DC, between 9 a.m. and 4 p.m., Monday through Friday, except Federal holidays.

Issued at Washington, DC, on March 9, 2007.

Rachel M. Samuel,

Deputy Advisory Committee Management Officer.

[FR Doc. E7–4756 Filed 3–14–07; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Office of Energy Efficiency and Renewable Energy

Agency Information Collection Revision

AGENCY: Office of Energy Efficiency and Renewable Energy, Department of Energy.

ACTION: Submission for Office of Management and Budget (OMB) review; comment request.

SUMMARY: The Department of Energy (DOE) has submitted an information collection revision package to OMB for review under the provisions of the Paperwork Reduction Act of 1995. The package requests revision of the information collection listed at the end of this notice. Comments are invited on: (a) Whether the revised information collections are necessary for the proper performance of the functions of the agency, including whether the information has practical utility; (b) the accuracy of the agency's estimate of the burden of the information collections, including the validity of the methodology and assumptions used; (c) ways to enhance the quality, utility, and clarity of the information to be collected; and (d) ways to minimize the burden of the information collections on respondents, including through the use of automated collection techniques or other forms of information technology.

DATES: Comments regarding this collection must be received on or before April 16, 2007. If you anticipate that you will be submitting comments, but find it difficult to do so within the period of time allowed by this notice, please advise the OMB Desk Officer of your intention to make a submission as soon as possible. The Desk Officer may be telephoned at 202–395–4650.

ADDRESSES: Written comments should be sent to: Christy Cooper, Office of Energy Efficiency and Renewable Energy, U.S. Department of Energy, EE–2H, 1000 Independence Avenue, SW., Washington, DC 20585, or by fax at 202–586–9811 or by e-mail at *Christy.cooper@ee.doe.gov*.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of the information collection instrument and instructions should be directed to Christy Cooper at the address listed above in **ADDRESSES**.

SUPPLEMENTARY INFORMATION: The information collection package listed in this notice for public comment include the following:

(1) *OMB No.:* 1910–5124. (2) *Package Title:* U.S. Department of Energy Hydrogen Program Assessment of Knowledge and Opinions on Hydrogen and Fuel Cell Technologies. (3) *Type of Review:* Revision of currently approved information collection. (4) *Purpose:* This information collection provides the Department with the information necessary to measure current knowledge and opinions concerning hydrogen and fuel cell technologies in the United States and to compare this measurement against a baseline established in 2004. (5) *Respondents:* 3,246. (6) *Estimated Number of Burden Hours:* 702.

Statutory Authority: Department of Energy Organization Act, Public Law 95–91.

Issued in Washington, DC, on March 7, 2007.

Alexander A. Karsner,

Assistant Secretary, Energy Efficiency and Renewable Energy.

[FR Doc. E7–4755 Filed 3–14–07; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. RP07–340–000]

Columbia Gas Transmission Corporation; Notice of Proposed Changes in FERC Gas Tariff

March 9, 2007.

Take notice that on March 6, 2007, Columbia Gas Transmission Corporation (Columbia) tendered for filing as part of its FERC Gas Tariff, Second Revised Volume No. 1, the following revised tariff sheets with a proposed effective date of June 1, 2007:

Fifth Revised Sheet No. 390
Original Sheet No. 390A
Sixth Revised Sheet No. 391
Second Revised Sheet No. 392

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as

appropriate. Such notices, motions, or protests must be filed in accordance with the provisions of Section 154.210 of the Commission's regulations (18 CFR 154.210). Anyone filing an intervention or protest must serve a copy of that document on the Applicant. Anyone filing an intervention or protest on or before the intervention or protest date need not serve motions to intervene or protests on persons other than the Applicant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the ''eFiling'' link at *http://www.ferc.gov.* Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

This filing is accessible on-line at *http://www.ferc.gov*, using the ''eLibrary'' link and is available for review in the Commission's Public Reference Room in Washington, DC. There is an ''eSubscription'' link on the Web site that enables subscribers to receive e-mail notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please e-mail *FERCOnlineSupport@ferc.gov*, or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Philis J. Posey,

Acting Secretary.

[FR Doc. E7–4719 Filed 3–14–07; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. RP07–341–000]

Transcontinental Gas Pipe Line Corporation; Notice of Proposed Changes in FERC Gas Tariff

March 9, 2007.

Take notice that on March 6, 2007, Transcontinental Gas Pipe Line Corporation (Transco) tendered for filing as part of its FERC Gas Tariff, Third Revised Volume No. 1, First Revised Thirty-Second Revised Sheet No. 28B and Second Substitute Thirty-Third Revised Sheet No. 28B, to become effective February 9, 2007 and March 1, 2007, respectively.

Transco states that copies of the filing are being mailed to affected customers and interested state commissions.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. Such notices, motions, or protests must be filed in accordance with the provisions of Section 154.210 of the Commission's regulations (18 CFR 154.210). Anyone filing an intervention or protest must serve a copy of that document on the Applicant. Anyone filing an intervention or protest on or before the intervention or protest date need not serve motions to intervene or protests on persons other than the Applicant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the ''eFiling'' link at *http://www.ferc.gov.* Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

This filing is accessible on-line at *http://www.ferc.gov*, using the ''eLibrary'' link and is available for review in the Commission's Public Reference Room in Washington, DC. There is an ''eSubscription'' link on the Web site that enables subscribers to receive e-mail notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please e-mail *FERCOnlineSupport@ferc.gov*, or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Philis J. Posey,

Acting Secretary.

[FR Doc. E7–4720 Filed 3–14–07; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. EL07–44–000]

Complainant: Dakota Wind Harvest, LLC, vs. Respondents: Midwest Independent Transmission System Operator, Inc., Montana-Dakota Utilities Company, Western Area Power Administration; Notice of Complaint

March 9, 2007.

Take notice that on March 8, 2007, Dakota Wind Harvest, LLC (Dakota Wind) pursuant to Rule 206 of the Rules of Practice and Procedures of the Commission, 18 CFR 385.206 and sections 206 and 215 of the Federal Power Act, hereby submits the Complaint Requesting Fast Track Processing against Midwest Independent Transmission System Operator, Inc. (Midwest ISO), Montana-Dakota Utilities Company (MDU) and Western Area Power Administration (Western). Dakota Wind is required to file this Complaint due to: (i) Midwest ISO's refusal to allow Dakota Wind's wind-powered electricity generation facility currently under development to commence operations without first having a Balancing Authority designated; (ii) MDU's and Western's refusal to serve as Balancing Authority despite the fact that the Project will be interconnected to the transmission system owned by MDU and located in the geographic area in which Western is the designated Balancing Authority; and (iii) Midwest ISO's and MDU's refusal to act to ensure that a Balancing Authority agrees to provide balancing serviced to Dakota Wind.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211, 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. The Respondent's answer and all interventions or protests must be filed on or before the comment date. The Respondent's answer, motions to intervene, and protests must be served on the Complainants.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the ''eFiling'' link at *http://www.ferc.gov*. Persons unable to file electronically

should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

This filing is accessible on-line at *http://www.ferc.gov*, using the ''eLibrary'' link and is available for review in the Commission's Public Reference Room in Washington, DC. There is an ''eSubscription'' link on the Web site that enables subscribers to receive e-mail notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please e-mail *FERCOnlineSupport@ferc.gov*, or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Comment Date: 5 p.m. eastern time on March 23, 2007.

Philis J. Posey,

Acting Secretary.

[FR Doc. E7–4714 Filed 3–14–07; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 349–115—Alabama]

Alabama Power Company; Notice of Availability of Environmental Assessment

March 9, 2007.

In accordance with the National Environmental Policy Act of 1969 and the Federal Energy Regulatory Commission's (Commission) regulations, 18 CFR Part 380 (Order No. 486, 52 FR 47897), the Office of Energy Projects has reviewed an application for non-project use of project lands and waters at the Martin Dam Project (FERC No. 349), and has prepared an environmental assessment (EA) for the proposal. The project is located on Lake Martin near Dadeville, in Tallapoosa County, Alabama.

In the application, Alabama Power (licensee) requests Commission authorization to permit The Pointe at Sunset Pointe, LLC (The Pointe) to install 30 boat slips as well as a pier/platform and floating-dock structure on Lake Martin, the project reservoir. These structures would serve the residents of condominiums that are located on adjoining project lands. The EA contains Commission staff's analysis of the potential environmental impacts of the proposal and concludes that approval of the proposal, as modified by the staff-identified alternative, would not constitute a major federal action significantly affecting the quality of the human environment.

The EA is attached to a Commission order titled ''Order Modifying and Approving Non-Project Use of Project Lands and Waters,'' which was issued February 22, 2007, and is available for review and reproduction at the Commission's Public Reference Room, located at 888 First Street, NE., Room 2A, Washington, DC 20426. The EA may also be viewed on the Commission's Web site at *http://www.ferc.gov* using the ''elibrary'' link. Enter the project number (prefaced by P- and excluding the last three digits) in the docket number field to access the document. For assistance, contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll-free at (866) 208–3676, or for TTY, contact (202) 502–8659.

Philis J. Posey,

Acting Secretary.

[FR Doc. E7–4718 Filed 3–14–07; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 12617–001]

Fall Creek Hydro, LLC; Notice Dismissing Filing as Deficient

March 9, 2007.

On January 10, 2007, Commission staff issued an order dismissing Fall Creek Hydro, LLC's (Fall Creek) application for a second three-year preliminary permit to study the proposed 4.7-megawattt Fall Creek Hydroelectric Project No. 12617, to be located at the existing U.S. Army Corps of Engineers' (Corps) Fall Creek Dam, on Fall Creek in Lane County, Oregon. On February 8, 2007, Fall Creek filed a timely request for rehearing, seeking reinstatement of its application.

Fall Creek's rehearing request is deficient because it fails to include a Statement of Issues section separate from its arguments, as required by Rule 713 of the Commission's Rules of Practice and Procedure.[1] Rule 713(c)(2) requires that a rehearing request must include a separate section entitled ''Statement of Issues'' listing each issue presented to the Commission in a separately enumerated paragraph that includes representative Commission and court precedent on which the participant is relying.[2] Under Rule 713, any issue not so listed will be deemed waived. Accordingly, Fall Creek's rehearing request is dismissed.[3]

In any event, Fall Creek's arguments on rehearing are without merit. The purpose of a preliminary permit is to maintain priority of application for a license during the term of the permit while the permittee conducts investigations and secures data necessary to determine the feasibility of the proposed project and, if the project is found to be feasible, prepares an acceptable development application. While an applicant is not precluded from seeking and obtaining a successive preliminary permit for the same site, it must demonstrate that, under the prior permit, it pursued the proposal in good faith and with due diligence.[4] A permittee seeking a successive permit is therefore required to take certain minimal steps, including filing six-month progress reports and consulting with the appropriate federal and state resource agencies.[5]

In October 2002, Commission staff granted Fall Creek a three-year preliminary permit to study its proposed project.[6] Upon expiration of the first permit term, Fall Creek immediately filed its application for a second permit. Commission staff dismissed Fall Creek's application for a successive permit, concluding that Fall Creek failed to prosecute diligently the requirements of its previous permit.

On rehearing, Fall Creek contends that it has made substantial progress in analyzing the proposed project's feasibility and completing the Pre-

[1] 18 CFR 385.713(c)(2) (2006). See Revision of Rules of Practice and Procedure Regarding Issue Identification, Order No. 663, 70 FR 55,723 (September 23, 2005), FERC Statutes and Regulations ¶ 31,193 (2005). See also, Order 663–A, effective March 23, 2006, which amended Order 663 to limit its applicability to rehearing requests. Revision of Rules of Practice and Procedure Regarding Issue Identification, Order No. 663–A, 71 FR 14,640 (March 23, 2006), FERC Statutes and Regulations ¶ 31,211 (2006).

[2] As explained in Order No. 663, the purpose of this requirement is to benefit all participants in a proceeding by ensuring that the filer, the Commission, and all other participants understand the issues raised by the filer, and to enable the Commission to respond to these issues. Having a clearly articulated Statement of Issues ensures that issues are properly raised before the Commission and avoids the waste of time and resources involved in litigating appeals regarding which the courts of appeals lack jurisdiction because the issues on appeal were not clearly identified before the Commission. *See* Order No. 663 at P 3–4.

[3] See, e.g., South Carolina Electric & Gas Company, 116 FERC ¶ 61,218 (2006); and Duke Power Company, LLC, 116 FERC ¶ 61,171 (2006).

[4] See Little Horn Energy Wyoming, Inc., 58 FERC ¶ 61,132 (1992).

[5] See Burke Dam Hydro Associates, 47 FERC ¶ 61,449 (1989).

[6] 101 FERC ¶ 62,038 (2002).

application Document (PAD),[7] a step in the license application process.[8] As evidence of its ''substantial progress'' and due diligence, Fall Creek states that it made two site visits (November 2002 and July 2003) and held two meetings (May 2006 and January 2007). It also describes nine ''consultations'' made in preparation of its PAD, all but one of which occurred in a ten-day period after the dismissal of its permit application.[9] Finally it cites to 52 documents, publications, and Web sites that it reviewed in preparing its PAD. These efforts are too little, too late.

Philis J. Posey,

Acting Secretary.

[FR Doc. E7–4716 Filed 3–14–07; 8:45 am]

BILLING CODE 6717–01–P

[7] The purpose of a PAD under the Commission's Integrated Licensing Process is to provide detailed information about a proposed project to enable interested entities to identify issues, develop study requests and study plans, and prepare documents analyzing any license application that may be filed. See 18 CFR 5.6 (2006).

[8] Fall Creek later filed its PAD and a notice of intent to file a license application in a new proceeding (docketed Project No. 12778–000) on February 16, 2007, eight days after the filing of its request for rehearing. Finding the PAD to be deficient, partially because of Fall Creek's failure to consult with the National Marine Fisheries Service and the U.S. Fish and Wildlife Service, staff by letter dated February 28, 2007, gave Fall Creek 75 days to file an updated PAD or an addendum to the originally filed PAD.

[9] The Corps is the only consulted federal entity and the Oregon Department of Fish and Wildlife the only consulted resource agency.

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Notice of Application Accepted for Filing and Soliciting Motions To Intervene and Protests

March 9, 2007.

Take notice that the following hydroelectric application has been filed with the Commission and is available for public inspection.

a. *Type of Application:* New Major License.

b. *Project No.:* 2242–078.

c. *Date Filed:* November 24, 2006.

d. *Applicant:* Eugene Water and Electric Board.

e. *Name of Project:* Carmen-Smith Hydroelectric Project.

f. *Location:* On the McKenzie River in Lane and Linn Counties, near McKenzie Bridge, Oregon. The project occupies approximately 560 acres of the Willamette National Forest.

g. *Filed Pursuant to:* Federal Power Act 16 U.S.C. 791(a)–825(r).

h. *Applicant Contact:* Randy L. Berggren, General Manager, Eugene Water and Electric Board, 500 East 4th Avenue, P.O. Box 10148, Eugene, OR 97440, (541) 484–2411.

i. *FERC Contact:* Bob Easton, (202) 502–6045 or *robert.easton@ferc.gov*.

j. *Deadline for filing motions to intervene and protests:* 60 days from the issuance date of this notice.

All documents (original and eight copies) should be filed with: Philis J. Posey, Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

The Commission's Rules of Practice require all intervenors filing documents with the Commission to serve a copy of that document on each person on the official service list for the project. Further, if an intervenor files comments or documents with the Commission relating to the merits of an issue that may affect the responsibilities of a particular resource agency, they must also serve a copy of the document on that resource agency.

Motions to intervene and protests may be filed electronically via the Internet in lieu of paper. The Commission strongly encourages electronic filings. See 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site (*http://www.ferc.gov*) under the ''e-Filing'' link.

k. This application has been accepted, but is not ready for environmental analysis at this time.

l. The Carmen-Smith Hydroelectric Project consists of two developments, the Carmen development and the Trail Bridge development. The Carmen development includes: (1) A 25-foot-high, 2,100-foot-long, and 10-foot-wide earthen Carmen diversion dam with a concrete weir spillway, (2) a 11,380-foot-long by 9.5-foot-diameter concrete Carmen diversion tunnel located on the right abutment of the spillway, (3) a 235-foot-high, 1,100-foot-long, and 15-foot-wide earthen Smith diversion dam with a gated Ogee spillway, (4) a 7,275-foot-long by 13.5 foot-diameter concrete-lined Smith power tunnel, (5) a 1,160-foot-long by 13-foot-diameter steel underground Carmen penstock, (6) a 86-foot-long by 79-foot-wide Carmen powerhouse, (7) two Francis turbines each with a generating capacity of 52.25 megawatts (MW) for a total capacity of 104.50 MW, (8) a 19-mile, 115-kilovolt (kV) transmission line that connects the Carmen powerhouse to the Bonneville Power Administration's Cougar-Eugene transmission line, and (9) appurtenant facilities.

The Trail Bridge development includes: (1) A 100-foot-high, 700-foot-long, and 24-foot-wide earthen Trail Bridge dam section with a gated Ogee spillway, (2) a 1,000-foot-long and 20-foot-wide emergency spillway section, (3) a 300-foot-long by 12-foot-diameter concrete penstock at the intake that narrows to a diameter of 7 feet, (4) a 66-foot-long by 61-foot-wide Trail Bridge powerhouse, (5) one Kaplan turbine with a generating capacity of 9.975 MW, and (6) a one-mile, 11.5-kV distribution line that connects the Trail Bridge powerhouse to the Carmen powerhouse.

m. A copy of the application is available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site at *http://www.ferc.gov* using the ''eLibrary'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll-free at 1–866–208–3676, or for TTY, (202) 502–8659. A copy is also available for inspection and reproduction at the address in item h above.

You may also register online at *http://www.ferc.gov/docs-filing/esubscription.asp* to be notified via e-mail of new filings and issuances related to this or other pending projects. For assistance, contact FERC Online Support.

n. Anyone may submit a protest or a motion to intervene in accordance with the requirements of Rules of Practice and Procedure, 18 CFR 385.210, 385.211, and 385.214. In determining the appropriate action to take, the Commission will consider all protests filed, but only those who file a motion to intervene in accordance with the Commission's Rules may become a party to the proceeding. Any protests or motions to intervene must be received on or before the specified deadline date for the particular application.

All filings must (1) Bear in all capital letters the title ''PROTEST'' or ''MOTION TO INTERVENE;'' (2) set forth in the heading the name of the applicant and the project number of the application to which the filing responds; (3) furnish the name, address, and telephone number of the person protesting or intervening; and (4) otherwise comply with the requirements of 18 CFR 385.2001 through 385.2005. Agencies may obtain copies of the application directly from the applicant. A copy of any protest or motion to intervene must be served upon each

representative of the applicant specified in the particular application.

Philis J. Posey,

Acting Secretary.

[FR Doc. E7–4717 Filed 3–14–07; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. AD07–8–000]

Review of Market Monitoring Policies; Second Notice of Technical Conference

March 9, 2007.

On January 25, 2007, the Federal Energy Regulatory Commission (Commission) announced that a conference will be held to review the Commission's general policies regarding market monitoring, on April 5, 2007, at the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426 in the Commission Meeting Room. The Commission had announced its intent to hold this conference in *PJM Interconnection, LLC., order on reh'g,* 117 FERC ¶ 61,263 (2006).

The Commission is making one change in the schedule with this notice, *viz.,* to change the beginning of the conference from 9:30 a.m. to 9 a.m. (EDT).

All interested persons are invited to attend. There is *no* registration fee to attend.

Proactive oversight of the activities of regulated entities is a relatively recent development in the history of the Commission's utility regulation, one largely driven by the Commission's efforts to make greater use of market forces to discipline the activities of regulated entities. A significant aspect of this oversight effort has been the development of market monitoring units (MMUs) in the Commission-regulated Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs), along with the establishment of independent market monitors (IMMs) of certain vertically integrated utilities as a condition of approving those utilities' mergers or acquisition of assets. In addition, almost five years ago, the Commission dedicated staff members, now located in the Office of Enforcement's Division of Energy Market Oversight (DEMO), to monitor natural gas and electricity markets. In that capacity, DEMO staff works closely with the MMUs and IMMs.

In the technical conference, the Commission would like to explore the effectiveness of MMUs and IMMs both in performing market oversight and in serving a variety of interested stakeholders. The Commission does not intend to evaluate any individual MMU or IMM or to discuss issues in any pending proceeding. Rather, the Commission would like to focus on the concepts and principles involved in market monitoring and the relationship between the market monitors and the Commission market monitoring staff, informed by the experience of the industry since the inception of market monitoring. Of course, the Commission does not go into this conference with a blank slate. To the contrary, the Commission has spoken on many occasions on the role of market monitors in generic and case-specific proceedings. The Commission also issued a policy statement in May 2005. *See Policy Statement on Market Monitoring Unit,* 111 FERC ¶ 61,267 (2005) (and citations therein). Accordingly, rather than hearing about what it has done, the Commission would like to hear about what it should do to improve its market monitoring program.

With these thoughts in mind, the technical conference will be made up of two panels, each examining the role and effectiveness of market monitors from their respective perspectives, especially as that relates to market monitoring in the RTOs and ISOs. The panelists may discuss the IMMs as well as the MMUs.

After time reserved for initial statements by the Members of the Commission starting at 9 a.m., the first panel (9:30 a.m. until 10:30 a.m.) will consist of individuals who have participated in, written about, or are otherwise informed about the development of the concept and function of market monitoring. Members of this panel will be asked to answer the following questions:

1. What is the Commission's market monitoring role in the context of ensuring the competitiveness of wholesale electricity markets?

2. How do MMUs (as a concept or function) generally serve or facilitate that role?

3. What changes, if any, in the current structure of MMUs could enhance their ability to assist the Commission in its market monitoring role?

4. Are there other industries that are subject to comparable monitoring activities, and, if so, how are these activities structured?

The next panel will be held in three parts (10:45 a.m. to 11:45 a.m., 12 noon to 1 p.m., and 2 p.m. to 3 p.m.) and will consist of representatives from the MMUs, the ISOs or RTOs, and the various Stakeholders (including market participants, state regulators, and consumers), respectively. Members of these panels will be asked to answer the following questions:

1. MMUs' Role With Respect to FERC:

• What are the key functions of the role that MMUs have performed?

• Should these functions be changed or improved?

• What changes, if any, in the current structure of MMUs would allow them to more effectively assist the Commission in performing its market oversight activities?

2. MMUs' Role with Respect to ISOs/RTOs:

• What are the key functions of the role that MMUs have performed with respect to the operations of the ISOs/RTOs, including the operation of the transmission grid and Day 1 or Day 2 energy markets?

• Should these functions be changed or improved?

• What changes, if any, in the current structure of MMUs would allow them to more effectively assist ISOs/RTOs?

3. MMUs' Role with Respect to the various Stakeholders:

• What are the key functions of the role that MMUs have performed with respect to stakeholders?

• Should these functions be changed or improved?

• What changes, if any, in the current structure of MMUs would allow them to more effectively assist stakeholders?

Anyone interested in serving on one of these panels should contact Saida Shaalan at 202–502–8278 or by e-mail at *Saida.Shaalan@ferc.gov* on or before March 22, 2007. Please be advised, however, that the Commission may not be able to accommodate everyone who asks to be a panelist. Persons interested in serving on panels are therefore encouraged to coordinate their positions and choose a single panel representative. The Commission will issue a subsequent notice naming the panelists and providing further guidance on the format for presentations, which will be limited in time (probably five minutes) to provide sufficient opportunity for discussion.

As stated in the first notice issued January 25, 2007, a free webcast of this event will be available through www.ferc.gov. Anyone with Internet access who desires to view this event can do so by accessing www.ferc.gov's Calendar of Events and locating this event in the Calendar. The event will contain a link to its webcast. The Capitol Connection provides technical support for the Web casts and offers

access to the meeting via phone bridge for a fee. If you have any questions, visit *http://www.CapitolConnection.org* or contact Danelle Perkowski or David Reininger at 703–993–3100.

Transcripts of the meeting will be available immediately for a fee from Ace Reporting Company (202–347–3700 or 1–800–336–6646). They will be available for free on the Commission's eLibrary system and on the events calendar approximately one week after the meeting.

FERC conferences and meetings are accessible under section 508 of the Rehabilitation Act of 1973. For accessibility accommodations please send an e-mail to *accessibility@ferc.gov* or call toll free (866) 208–3372 (voice) or 202–502–8659 (TTY), or send a fax to 202–208–2106 with the required accommodations.

Philis J. Posey,

Acting Secretary.

[FR Doc. E7–4713 Filed 3–14–07; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Notice of Membership of Performance Review Board for Senior Executives (PRB)

March 9, 2007.

The Federal Energy Regulatory Commission hereby provides notice of the membership of its Performance Review Board (PRB) for the Commission's Senior Executive Service (SES) members. The function of this board is to make recommendations relating to the performance of senior executives in the Commission. This action is undertaken in accordance with Title 5, U.S.C. 4314(c)(4). The Commission's PRB will remove the following member: Daniel L. Larcamp.

Philis J. Posey,

Acting Secretary.

[FR Doc. E7–4715 Filed 3–14–07; 8:45 am]

BILLING CODE 6717–01–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–8288–2]

Proposed Consent Decree Clean Air Act Citizen Suit

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of proposed consent decree; request for public comment.

SUMMARY: In accordance with section 113(g) of the Clean Air Act, as amended (''Act''), 42 U.S.C. 7413(g), notice is hereby given of a proposed consent decree, to address a lawsuit filed by the Sierra Club: *Sierra Club* v. *The United States Environmental Protection Agency,* No. CV 06–00663 BB(LFG) (District of New Mexico). On or about July 26, 2006, Sierra Club filed a complaint alleging that EPA had failed to perform a non-discretionary duty and had unreasonably delayed publication of a final rule, known as a Federal Implementation Plan (''FIP''), regulating air emissions from the Four Corners Power Plant (''FCPP''). Under the terms of the proposed consent decree, a deadline of April 30, 2007, is established for EPA to take final action on the FIP proposed by EPA on September 12, 2006.

DATES: Written comments on the proposed consent decree must be received by *April 16, 2007.*

ADDRESSES: Submit your comments, identified by Docket ID number EPA–HQ7–OGC–2007–0194, online at *http://www.regulations.gov* (EPA's preferred method); by e-mail to *oei.docket@epa.gov;* mailed to EPA Docket Center, Environmental Protection Agency, Mailcode: 2822T, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001; or by hand delivery or courier to EPA Docket Center, EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC, between 8:30 a.m. and 4:30 p.m. Monday through Friday, excluding legal holidays. Comments on a disk or CD–ROM should be formatted in Word or ASCII file, avoiding the use of special characters and any form of encryption, and may be mailed to the mailing address above. Please provide a separate copy of your comments to the person identified in the For Further Information Contact section of this notice.

FOR FURTHER INFORMATION CONTACT: Richard H. Vetter, c/o Cheryl Graham Air and Radiation Law Office (2344A), Office of General Counsel, U.S. Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460; telephone: (919) 541–2127; fax number (919) 541–4991; email address: *vetter.rick@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. Additional Information About the Proposed Consent Decree

The proposed consent decree would resolve the suit filed by Sierra Club alleging that EPA had a non-discretionary duty and had unreasonably delayed finalizing a FIP regulating air emissions from FCPP.

The background to Sierra Club's Complaint is that EPA had proposed a FIP in 1999 for FCPP, see 64 FR 48731 (September 8, 1999), but by 2006 had not taken final action on the 1999 proposed FIP. Shortly after 1999, FCPP began negotiations with EPA, Navajo Nation EPA, the National Park Service and several environmental groups (not including Sierra Club). Between 2003 and 2005, FCPP tested changes to its SO2 control devices that increased the overall control efficiency of these control devices.

EPA proposed a new FIP for FCPP on September 12, 2006 that, among other things, reflected the increase in efficiency of the SO2 control devices at the facility. 71 FR 53631. The proposed consent decree provides that on or before April 30, 2007, EPA will take final action on the FIP we proposed on September 12, 2006.

On December 14, 2006, the parties filed with the Court a notice of lodging of the proposed consent decree. The notice informed the Court of the decree but noted that the decree was not ready for entry as it is subject to the requirements of section 113(g) of the Clean Air Act.

For a period of thirty (30) days following the date of publication of this notice, the Agency will receive written comments relating to the proposed consent decree from persons who were not named as parties to the litigation in question. EPA or the Department of Justice may withdraw or withhold consent to the proposed consent decree if the comments disclose facts or considerations that indicate that such consent is inappropriate, improper, inadequate, or inconsistent with the requirements of the Act. Unless EPA or the Department of Justice determines, based on any comment which may be submitted, that consent to the consent decree should be withdrawn, the terms of the decree will be affirmed.

II. Additional Information About Commenting on the Proposed Consent Decree

A. How Can I Get a Copy of the Consent Decree?

The official public docket for this action (identified by Docket ID No. EPA7–HQ–OGC–2007–0194) contains a copy of the proposed consent decree. The official public docket is available for public viewing at the Office of Environmental Information (OEI) Docket in the EPA Docket Center, EPA West,

Room 3334, 1301 Constitution Ave., NW., Washington, DC. The EPA Docket Center Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the OEI Docket is (202) 566–1752.

An electronic version of the public docket is available through *http://www.regulations.gov.* You may use the *www.regulations.gov* to submit or view public comments, access the index listing of the contents of the official public docket, and to access those documents in the public docket that are available electronically. Once in the system, select ''search,'' then key in the appropriate docket identification number.

It is important to note that EPA's policy is that public comments, whether submitted electronically or in paper, will be made available for public viewing online at *http://www.regulations.gov* without change, unless the comment contains copyrighted material, CBI, or other information whose disclosure is restricted by statute. Information claimed as CBI and other information whose disclosure is restricted by statute is not included in the official public docket or in the electronic public docket. EPA's policy is that copyrighted material, including copyrighted material contained in a public comment, will not be placed in EPA's electronic public docket but will be available only in printed, paper form in the official public docket. Although not all docket materials may be available electronically, you may still access any of the publicly available docket materials through the EPA Docket Center.

B. How and To Whom Do I Submit Comments?

You may submit comments as provided in the **ADDRESSES** section. Please ensure that your comments are submitted within the specified comment period. Comments received after the close of the comment period will be marked ''late.'' EPA is not required to consider these late comments.

If you submit an electronic comment, EPA recommends that you include your name, mailing address, and an e-mail address or other contact information in the body of your comment and with any disk or CD ROM you submit. This ensures that you can be identified as the submitter of the comment and allows EPA to contact you in case EPA cannot read your comment due to technical difficulties or needs further information on the substance of your comment. Any identifying or contact information provided in the body of a comment will be included as part of the comment that is placed in the official public docket, and made available in EPA's electronic public docket. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment.

Use of the *www.regulations.gov* Web site to submit comments to EPA electronically is EPA's preferred method for receiving comments. The electronic public docket system is an ''anonymous access'' system, which means EPA will not know your identity, e-mail address, or other contact information unless you provide it in the body of your comment. In contrast to EPA's electronic public docket, EPA's electronic mail (e-mail) system is not an ''anonymous access'' system. If you send an e-mail comment directly to the Docket without going through *www.regulations.gov*, your e-mail address is automatically captured and included as part of the comment that is placed in the official public docket, and made available in EPA's electronic public docket.

Dated: March 8, 2007.

Richard B. Ossias,

Associate General Counsel.

[FR Doc. E7–4778 Filed 3–14–07; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–8287–7]

Clean Water Act Section 303(d): Availability of List Decisions

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of availability.

SUMMARY: This action announces the availability of EPA decisions identifying water quality limited segments and associated pollutants in California to be listed pursuant to Clean Water Act section 303(d)(2), and requests public comment. Section 303(d)(2) requires that states submit and EPA approve or disapprove lists of waters for which existing technology-based pollution controls are not stringent enough to attain or maintain state water quality standards and for which total maximum daily loads (TMDLs) must be prepared.

On November 30, 2006, EPA partially approved California's 2004–2006 303(d) submittal. Specifically, EPA approved California's proposal to list impaired waters and associated pollutants. On March 8, 2007, EPA partially disapproved California's decisions not to list 64 water quality limited segments and associated pollutants, and additional pollutants for 37 water bodies already listed by the State. EPA identified these additional water bodies and pollutants for inclusion on the State's 2004–2006 section 303(d) list.

EPA is providing the public the opportunity to review its decisions to add waters and pollutants to California 2004–2006 section 303(d) list, as required by EPA's Public Participation regulations. EPA will consider public comments in reaching its final decisions on the additional water bodies and pollutants identified for inclusion on California's final lists.

DATES: Comments must be submitted to EPA on or before April 16, 2007.

ADDRESSES: Comments on the proposed decisions should be sent to Peter Kozelka, TMDL Liaison, Water Division (WTR–2), U.S. Environmental Protection Agency Region IX, 75 Hawthorne Street, San Francisco, CA 94105, telephone (415) 972–3448, facsimile (415) 947–3537, e-mail *kozelka.peter@epa.gov.* Oral comments will not be considered. Copies of the decisions concerning California's 303(d) list which explain the rationale for EPA's decisions can be obtained at EPA Region 9's Web site at *http://www.epa.gov/region9/water/tmdl/303d.html* by writing or calling Mr. Kozelka at the above address. Underlying documentation comprising the record for these decisions is available for public inspection at the above address.

FOR FURTHER INFORMATION CONTACT: Peter Kozelka at (415) 972–3448 or *kozelka.peter@epa.gov.*

SUPPLEMENTARY INFORMATION: Section 303(d) of the Clean Water Act (CWA) requires that each state identify those waters for which existing technology-based pollution controls are not stringent enough to attain or maintain state water quality standards. For those waters, states are required to establish TMDLs according to a priority ranking.

EPA's Water Quality Planning and Management regulations include requirements related to the implementation of Section 303(d) of the CWA (40 CFR 130.7). The regulations require states to identify water quality limited waters still requiring TMDLs every two years. The lists of waters still needing TMDLs must also include priority rankings and must identify the waters targeted for TMDL development during the next two years (40 CFR 130.7). On March 31, 2000, EPA promulgated a revision to this

regulation that waived the requirement for states to submit Section 303(d) lists in 2000 except in cases where a court order, consent decree, or settlement agreement required EPA to take action on a list in 2000 (65 FR 17170).

Consistent with EPA's regulations, California submitted to EPA its listing decisions under Section 303(d)(2) on November 24, 2006. On November 30, 2006, EPA approved California's list of impaired waters, except Walnut Creek Toxicity. EPA disapproved California's decisions not to list 64 water quality limited segments and associated pollutants, and additional pollutants for 37 water bodies already listed by the State. EPA identified these additional waters and pollutants for inclusion on the 2004–2006 Section 303(d) list. EPA solicits public comment on its identification of these additional waters and associated pollutants for inclusion on California's 2004–2006 Section 303(d) list.

Dated: March 8, 2007.

Alexis Strauss,

Director, Water Division, Region IX.

[FR Doc. E7–4663 Filed 3–14–07; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL DEPOSIT INSURANCE CORPORATION

Agency Information Collection Activities: Proposed Collection Renewals; Comment Request

AGENCY: Federal Deposit Insurance Corporation (FDIC).

ACTION: Notice and request for comment.

SUMMARY: The FDIC, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other federal agencies to take this opportunity to comment on continuing information collections, as required by the Paperwork Reduction Act of 1995 (44 U.S.C. chapter 35). Currently, the FDIC is soliciting comments concerning the following collections of information titled: Application For Consent to Exercise Trust Powers (3064–0025); Asset Securitization (3064–0137); and Insurance Sales Consumer Protections (3064–0140).

DATES: Comments must be submitted on or before May 14, 2007.

ADDRESSES: Interested parties are invited to submit written comments by any of the following methods. All comments should refer to the name and number of the collection:

- *http://www.FDIC.gov/regulations/laws/federalnotices.html*.
- E-mail: *comments@fdic.gov*. Include the name and number of the collection in the subject line of the message.
- Mail: Steve Hanft (202–898–3907), Clearance Officer, Federal Deposit Insurance Corporation, 550 17th Street, NW., Washington, DC 20429.
- Hand Delivery: Comments may be hand-delivered to the guard station at the rear of the 550 17th Street Building (located on F Street), on business days between 7 a.m. and 5 p.m.

A copy of the comments may also be submitted to the OMB Desk Officer for the FDIC, Office of Information and Regulatory Affairs, Office of Management and Budget, New Executive Office Building, Washington, DC 20503.

FOR FURTHER INFORMATION CONTACT: Steve Hanft (address above).

SUPPLEMENTARY INFORMATION:

1. *Title:* Application for Consent to Exercise Trust Powers.

OMB Number: 3064–0025.

Form Number: FDIC 6200/09.

Frequency of Response: On occasion.

Affected Public: Insured state nonmember banks wishing to exercise trust powers.

Estimated Number of Respondents: 18.

Estimated Time per Response for Eligible Depository Institutions: 8 hours.

Estimated Time per Response for Institutions that do not Qualify as Eligible Institutions: 24 hours.

Total Annual Burden: 208 hours.

General Description of Collection: FDIC regulations (12 CFR 333.2) prohibit any insured state nonmember bank from changing the general character of its business without the prior written consent of the FDIC. The exercise of trust powers by a bank is usually considered to be a change in the general character of a bank's business if the bank did not exercise those powers previously. Therefore, unless a bank is currently exercising trust powers, it must file a formal application to obtain the FDIC's written consent to exercise trust powers. State banking authorities, not the FDIC, grant trust powers to their banks. The FDIC merely consents to the exercise of such powers. Applicants use form FDIC 6200/09 to obtain FDIC's consent.

2. *Title:* Interagency Guidance on Asset Securitization Activities.

OMB Number: 3064–0137.

Form Number: None.

Frequency of Response: On occasion.

Affected Public: Insured state nonmember banks involved in asset securitization activities.

Estimated Number of Responses: 20.

Estimated Time per Response: 7.45 hours.

Total Annual Burden: 149 hours.

General Description of Collection: The collection applies to institutions engaged in asset securitization and consists in recordkeeping requirements associated with developing or upgrading a written asset securitization policy, documenting fair value of retained interests, and a management information system to monitor securitization activities. Bank managements use this information as the basis for the safe and sound operation of their asset securitization activities and to ensure that they minimize operational risk in these activities. The FDIC uses the information to evaluate the quality of an institution's risk management practices, and to assist institutions without proper internal supervision of their asset securitization activities to implement corrective action to conduct these activities in a safe and sound manner.

3. *Title:* Consumer Protections for Depository Institution Sales of Insurance.

OMB Number: 3064–0140.

Form Number: None.

Frequency of Response: On occasion.

Affected Public: Insured state nonmember banks that sell insurance products; persons who sell insurance products in or on behalf of insured state nonmember banks.

Estimated Number of Respondents: 2,670.

Estimated Time per Response: 1 hour.

Total Annual Burden: 2,670 hours.

General Description of Collection: Respondents must prepare and provide certain disclosures to consumers (*e.g.*, that insurance products and annuities are not FDIC-insured) and obtain consumer acknowledgments, at two different times: (1) Before the completion of the initial sale of an insurance product or annuity to a consumer; and (2) at the time of application for the extension of credit (if insurance products or annuities are sold, solicited, advertised, or offered in connection with an extension of credit).

Request for Comment

Comments are invited on: (a) Whether these collections of information are necessary for the proper performance of the FDIC's functions, including whether the information has practical utility; (b) the accuracy of the estimates of the burden of the information collections, including the validity of the methodology and assumptions used; (c) ways to enhance the quality, utility, and clarity of the information to be collected; and (d) ways to minimize the

burden of the information collections on respondents, including through the use of automated collection techniques or other forms of information technology.

At the end of the comment period, the comments and recommendations received will be analyzed to determine the extent to which the collections should be modified prior to submission to OMB for review and approval. Comments submitted in response to this notice also will be summarized or included in the FDIC's requests to OMB for renewal of these collections. All comments will become a matter of public record.

Dated at Washington, DC, this 9th day of March, 2007.

Federal Deposit Insurance Corporation.

Robert E. Feldman,

Executive Secretary.

[FR Doc. E7–4678 Filed 3–14–07; 8:45 am]

BILLING CODE 6714–01–P

FEDERAL ELECTION COMMISSION

Sunshine Act Meeting; Notice

* * * * *

DATE AND TIME: Tuesday, March 20, 2007 at 10 a.m.

PLACE: 999 E Street, NW., Washington, DC.

STATUS: This meeting will be closed to the public.

ITEMS TO BE DISCUSSED: Compliance matters pursuant to 2 U.S.C. 437g. Audits conducted pursuant to 2 U.S.C. 437g, 438(b), and Title 26, U.S.C. Matters concerning participation in civil actions or proceedings or arbitration. Internal personnel rules and procedures or matters affecting a particular employee.

PERSON TO CONTACT FOR INFORMATION: Mr. Robert Biersack, Press Officer, Telephone: (202) 694–1220.

Mary W. Dove,

Secretary of the Commission.

[FR Doc. 07–1284 Filed 3–13–07; 12:38 pm]

BILLING CODE 6715–01–M

FEDERAL RESERVE SYSTEM

Change in Bank Control Notices; Acquisition of Shares of Bank or Bank Holding Companies

The notificants listed below have applied under the Change in Bank Control Act (12 U.S.C. 1817(j)) and § 225.41 of the Board's Regulation Y (12 CFR 225.41) to acquire a bank or bank holding company. The factors that are considered in acting on the notices are set forth in paragraph 7 of the Act (12 U.S.C. 1817(j)(7)).

The notices are available for immediate inspection at the Federal Reserve Bank indicated. The notices also will be available for inspection at the office of the Board of Governors. Interested persons may express their views in writing to the Reserve Bank indicated for that notice or to the offices of the Board of Governors. Comments must be received not later than March 29, 2007.

A. Federal Reserve Bank of Atlanta (David Tatum, Vice President) 1000 Peachtree Street, N.E., Atlanta, Georgia 30309:

1. Bill Blanton, Alpharetta, Georgia, as an individual, and a group acting in concert consisting of Bill Blanton, Alpharetta; Gilbert T. Jones, Sr., Jane Jones, Jewels Jones, Brandy Jones, and Barbe Jones, all of Comer; Paula M. Allen, of Dahlonega; Areatha J. Keesey, of Oakwood; Kathy L. Cooper, John Cooper, Tyler Cooper, and Donn H. Cooper, all of Flowery Branch; Robert Allen, of Manchester; Shelley Palmour Anderson, Lanny W. Dunagan, Ann M. Palmour, Wendell A. Turner, Howard Bridges, Rebecca Harrison, James H. McBride, James E. Palmour, Kim Hunter, Victoria Leigh Hunter, Paden Dunagan, C. Danny Dunagan, all of Gainesville; and David C. Harwell, LaVerne Harwell, Douglas F. Harwell, Alice Lipscomb, and Franklin D. Harwell, Jr., all of Winder; all of Georgia, to acquire control of NBOG Bancorporation, Inc., Gainesville, Georgia, and thereby acquire control of The National Bank of Gainesville, Gainesville, Georgia.

Board of Governors of the Federal Reserve System, March 12, 2007.

Robert deV. Frierson,

Deputy Secretary of the Board.

[FR Doc. E7–4793 Filed 3–14–07; 8:45 am]

BILLING CODE 6210–01–S

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

Disease, Disability, and Injury Prevention and Control Special Emphasis Panel: Cooperative Agreement to the Medical Research Council of South Africa for TB Control and HIV Prevention, Care and Treatment Activities, Program Announcement (PA) Number PS07–006

In accordance with section 10(a)(2) of the Federal Advisory Committee Act (Pub. L. 92–463), the Centers for Disease Control and Prevention (CDC) announces a meeting of the aforementioned Special Emphasis Panel.

Time and Date: 1 p.m.–2:30 p.m., May 11, 2007 (Closed).

Place: Teleconference. Corporate Square, Building 8, Conference Room 6B.

Status: The meeting will be closed to the public in accordance with provisions set forth in section 552b(c)(4) and (6), Title 5 U.S.C., and the Determination of the Director, Management Analysis and Services Office, CDC, pursuant to Pub. L. 92–463.

Matters To Be Discussed: The meeting will include the review, discussion, and evaluation of a research application in response to PA PS07–006, ''Cooperative Agreement to the Medical Research Council of South Africa for TB Control and HIV Prevention, Care and Treatment Activities.''

For Further Information Contact: J. Felix Rogers, Scientific Review Administrator, Centers for Disease Control and Prevention, 1600 Clifton Road, NE., MS E05, Atlanta, GA 30333, telephone 404.639.6101.

The Director, Management Analysis and Services Office, has been delegated the authority to sign **Federal Register** notices pertaining to announcements of meetings and other committee management activities, for both CDC and the Agency for Toxic Substances and Disease Registry.

Dated: March 8, 2007.

Elaine L. Baker,

Acting Director, Management Analysis and Services Office, Centers for Disease Control and Prevention.

[FR Doc. E7–4743 Filed 3–14–07; 8:45 am]

BILLING CODE 4163–18–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

Disease, Disability, and Injury Prevention and Control Special Emphasis Panel (SEP): China-United States Collaborative, Population-Based Surveillance and Research Program for Maternal-Child and Family Health, Request for Applications (RFA) DD07–006

In accordance with Section 10(a)(2) of the Federal Advisory Committee Act (Pub. L. 92–463), the Centers for Disease Control and Prevention (CDC) announces the following meeting of the aforementioned SEP:

Time and Date: 1 p.m.–3 p.m., April 26, 2007 (Closed).

Place: Teleconference. Centers for Disease Control and Prevention, 1600 Clifton Road, Atlanta, GA 30333.

Status: The meeting will be closed to the public in accordance with provisions set forth in Section 552b(c)(4) and (6), Title 5 U.S.C., and the Determination of the Director,

Management Analysis and Services Office, CDC, pursuant to Public Law 92–463.

Matters To Be Discussed: The meeting will include the review, discussion, and evaluation of scientific merit of grant applications received in response to RFA DD07–006, ''China-United States Collaborative, Population-Based Surveillance and Research Program for Maternal-Child and Family Health.''

For Further Information Contact: Juliana Cyril, Ph.D., Scientific Review Administrator, Centers for Disease Control and Prevention, 1600 Clifton Road NE, Mailstop D72, Atlanta, GA 30333, Telephone 404.639.4639.

The Director, Management Analysis and Services Office, has been delegated the authority to sign **Federal Register** notices pertaining to announcements of meetings and other committee management activities, for both CDC and the Agency for Toxic Substances and Disease Registry.

Dated: March 8, 2007.

Elaine L. Baker,

Acting Director, Management Analysis and Services Office, Centers for Disease Control and Prevention.

[FR Doc. E7–4744 Filed 3–14–07; 8:45 am]

BILLING CODE 4163–18–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

Disease, Disability, and Injury Prevention and Control Special Emphasis Panel (SEP): Childhood Agriculture Safety and Health Research, Request for Applications (RFA) OH 07–002

In accordance with Section 10(a)(2) of the Federal Advisory Committee Act (Pub. L. 92–463), the Centers for Disease Control and Prevention (CDC) announces the aforementioned meeting.

Time and Date: 1 p.m.–3 p.m., April 16, 2007 (Closed).

Place: Teleconference.

Status: The meeting will be closed to the public in accordance with provisions set forth in Section 552b(c)(4) and (6), Title 5 U.S.C., and the Determination of the Director, Management Analysis and Services Office, CDC, pursuant to Public Law 92–463.

Matters to be Discussed: The meeting will include the review, discussion, and evaluation of applications received in response to RFA OH 07–002, ''Childhood Agriculture Safety and Health Research.''

Contact Person For More Information: Stephen Olenchock, Scientific Review Administrator, Office of Extramural Coordination and Special Projects, National Institute for Occupational Safety and Health, CDC, 1095 Willowdale Road, Mailstop P–04, Morgantown, WV 26506, Telephone 304–285–6271.

The Director, Management Analysis and Services Office, has been delegated the authority to sign **Federal Register** notices pertaining to announcements of meetings and other committee management activities, for both CDC and the Agency for Toxic Substances and Disease Registry.

Elaine L. Baker,

Acting Director, Management Analysis and Services Office, Centers for Disease Control and Prevention.

[FR Doc. E7–4745 Filed 3–14–07; 8:45 am]

BILLING CODE 4163–18–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. 2006N–0472]

Agency Information Collection Activities; Submission for Office of Management and Budget Review; Comment Request; Substances Prohibited From Use in Animal Food or Feed; Animal Proteins Prohibited in Ruminant Feed

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) is announcing that a proposed collection of information has been submitted to the Office of Management and Budget (OMB) for review and clearance under the Paperwork Reduction Act of 1995.

DATES: Fax written comments on the collection of information by April 16, 2007.

ADDRESSES: To ensure that comments on the information collection are received, OMB recommends that written comments be faxed to the Office of Information and Regulatory Affairs, OMB, Attn: FDA Desk Officer, FAX: 202–395–6974.

FOR FURTHER INFORMATION CONTACT: Denver Presley, Jr., Office of the Chief Information Officer (HFA–250), Food and Drug Administration, 5600 Fishers Lane, Rockville, MD 20857, 301– 827–1472.

SUPPLEMENTARY INFORMATION: In compliance with 44 U.S.C. 3507, FDA has submitted the following proposed collection of information to OMB for review and clearance.

Substances Prohibited from Use in Animal Food or Feed; Animal Proteins Prohibited in Ruminant Feed—21 CFR 589.2000(e)(1)(iv) (OMB Control Number 0910–0339)—Extension

This information collection was established because epidemiological evidence gathered in the United Kingdom suggested that bovine spongiform encephalopathy (BSE), a progressively degenerative central nervous system disease, is spread to ruminant animals by feeding protein derived from ruminants infected with BSE. That regulation places general requirements on persons that manufacture, blend, process, and distribute products that contain or may contain protein derived from mammalian tissue, and feeds made from such products.

In the **Federal Register** of December 4, 2006 (71 FR 70409), FDA published a 60-day notice requesting public comment on the information collection provisions. No comments were received.

The respondents for this collection of information are manufacturers and or distributors of products that contain or may contain protein derived from mammalian tissues and feeds made from such products.

TABLE 1.—ESTIMATED ANNUAL RECORDKEEPING BURDEN[1]

21 CFR Section	No. of Recordkeepers	Annual Frequency per Recordkeeping	Total Annual Records	Hours per Record	Total Hours
589.2000(e)(1)(iv)	400	1	400	14	5,600

[1]There are no capital costs or operating and maintenance costs associated with this collection of information.

Dated: March 7, 2007.

Jeffrey Shuren,

Assistant Commissioner for Policy.

[FR Doc. E7–4685 Filed 3–14–07; 8:45 am]

BILLING CODE 4160–01–S

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket Nos. 2006M–0384, 2006M–0385, 2006M–0386]

Medical Devices Regulated by the Center for Biologics Evaluation and Research; Availability of Summaries of Safety and Effectiveness Data for Premarket Approval Applications

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) is publishing a list of premarket approval applications (PMAs) that have been approved by the Center for Biologics Evaluation and Research (CBER). This list is intended to inform the public of the availability through the Internet and the FDA's Division of Dockets Management of summaries of safety and effectiveness data of approved PMAs.

ADDRESSES: Submit written requests for copies of summaries of safety and effectiveness data to the Division of Dockets Management (HFA–305), Food and Drug Administration, 5630 Fishers Lane, rm. 1061, Rockville, MD 20852. Please include the appropriate docket number as listed in tables 1 and 2 of this document when submitting a written request. See the **SUPPLEMENTARY INFORMATION** section for electronic access to the summaries of safety and effectiveness data.

FOR FURTHER INFORMATION CONTACT: Nathaniel L. Geary, Center for Biologics Evaluation and Research (HFM–17), Food and Drug Administration, suite 200N, 1401 Rockville Pike, Rockville, MD 20852–1448, 301–827–6210.

SUPPLEMENTARY INFORMATION:

I. Background

In the **Federal Register** of January 30, 1998 (63 FR 4571), FDA published a final rule that revised 21 CFR 814.44(d) and 814.45(d)) to discontinue individual publication of PMA approvals and denials in the **Federal Register**, providing instead to post this information on the Internet at *http://www.fda.gov*. In addition, the regulations provide that FDA publish a quarterly list of available safety and effectiveness summaries of PMA approvals and denials that were announced during the quarter. FDA believes that this procedure expedites public notification of these actions because announcements can be placed on the Internet more quickly than they can be published in the **Federal Register**, and FDA believes that the Internet is accessible to more people than the **Federal Register**.

In accordance with section 515(d)(4) and (e)(2) of the Federal Food, Drug, and Cosmetic Act (the act) (21 U.S.C. 360e(d)(4) and (e)(2)), notification of an order approving, denying, or withdrawing approval of a PMA will continue to include a notice of opportunity to request review of the order under section 515(g) of the act. The 30-day period for requesting administrative reconsideration of an FDA action under § 10.33(b) (21 CFR 10.33(b)) for notices announcing approval of a PMA begins on the day the notice is placed on the Internet. Section 10.33(b) provides that FDA may, for good cause, extend this 30-day period. Reconsideration of a denial or withdrawal of approval of a PMA may be sought only by the applicant; in these cases, the 30-day period will begin when the applicant is notified by FDA in writing of its decision.

The following is a list of PMAs approved by CBER for which summaries of safety and effectiveness data were placed on the Internet from March 1, 2006, through June 30, 2006, and from July 1, 2006, through September 30, 2006. There were no denial actions during either period. The list provides the manufacturer's name, the product's generic name or the trade name, and the approval date.

TABLE 1.—LIST OF SUMMARIES OF SAFETY AND EFFECTIVENESS DATA FOR APPROVED PMAS MADE AVAILABLE MARCH 1, 2006, THROUGH JUNE 30, 2006

PMA No./Docket No.	Applicant	Trade Name	Approval Date
BP050009/0/2006M–0384	Chembio Diagnostic Systems, Inc.	SURE CHECK HIV 1/2 ASSAY	May 25, 2006
BP050010/0/2006M–0385	Chembio Diagnostic Systems, Inc.	HIV 1/2 STAT–PAKT ASSAY	May 25, 2006

TABLE 2.—LIST SUMMARIES OF SAFETY AND EFFECTIVENESS DATA FOR APPROVED PMAS MADE AVAILABLE JULY 1, 2006, THROUGH SEPTEMBER 30, 2006

PMA No./Docket No.	Applicant	Trade Name	Approval Date
BP050030/0/2006M–0386	Bayer Healthcare LLC	ADVIA Centaur HIV 1/0/2 Enhanced Assay	May 18, 2006

II. Electronic Access

Persons with access to the Internet may obtain the documents at *http://www.fda.gov/cber/products.htm*.

Dated: March 5, 2007.

Jeffrey Shuren,

Assistant Commissioner for Policy.

[FR Doc. E7–4677 Filed 3–14–07; 8:45 am]

BILLING CODE 4160–01–S

DEPARTMENT OF HOMELAND SECURITY

National Communications System

[Docket No. NCS–2007–0001]

National Security Telecommunications Advisory Committee

AGENCY: National Communications System, DHS.

ACTION: Notice of partially closed advisory committee meeting.

SUMMARY: The President's National Security Telecommunications Advisory Committee (NSTAC) will be meeting by teleconference: the meeting will be partially closed.

DATES: Thursday, March 29, 2007, from 2 p.m. until 3 p.m.

ADDRESSES: The meeting will take place by teleconference. For access to the conference bridge and meeting materials, contact Mr. Kelvin Coleman at (703) 235–5643 or by e-mail at *kelvin.coleman@dhs.gov* by 5 p.m. on Friday, March 23, 2007. If you desire to submit comments, they must be submitted by April 5, 2007. Comments must be identified by NCS–2007–0001 and may be submitted by *one* of the following methods:

• *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.

• *E-mail: NSTAC1@dhs.gov.* Include docket number in the subject line of the message.

• *Mail:* Office of the Manager, National Communications System (N5), Department of Homeland Security, Washington, DC, 20529.

• *Fax:* 1–866–466–5370.

Instructions: All submissions received must include the words ''Department of Homeland Security'' and NCS–2007–0001, the docket number for this action. Comments received will be posted without alteration at *www.regulations.gov*, including any personal information provided.

Docket: For access to the docket to read background documents or comments received by the NSTAC, go to *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Ms. Kiesha Gebreyes, Chief, Industry Operations Branch at (703) 235–5525, e-mail: *Kiesha.Gebreyes@dhs.gov* or write the Deputy Manager, National Communications System, Department of Homeland Security, IP/NCS/N5.

SUPPLEMENTARY INFORMATION: The NSTAC advises the President on issues and problems related to implementing national security and emergency preparedness telecommunications policy. Notice of this meeting is given under the Federal Advisory Committee Act (FACA), Public Law 92–463, as amended (5 U.S.C. App.1 *et seq.*).

At the upcoming meeting, between 2 p.m. and 2:25 p.m., the members will receive comments from government stakeholders and receive an update from the NSTAC's International Task Force (ITF). This portion of the meeting will be open to the public.

Between 2:25 p.m. and 3 p.m., the committee will discuss Global Infrastructure Resiliency (GIR). This portion of the meeting will be closed to the public.

Persons with disabilities who require special assistance should indicate this when arranging access to the teleconference and are encouraged to identify anticipated special needs as early as possible.

Basis for Closure: The GIR discussion will likely involve sensitive infrastructure information concerning system threats and explicit physical/cyber vulnerabilities of the undersea communications infrastructure. Public disclosure of such information would heighten awareness of potential vulnerabilities and increase the likelihood of exploitation by terrorists or other motivated adversaries. Pursuant to Section 10(d) of the Federal Advisory Committee Act, Public Law 92–463, as amended (5 U.S.C. App. 1 *et seq.*), the Department has determined that this discussion will concern matters which, if disclosed, would be likely to frustrate significantly the implementation of a proposed agency action. Accordingly, the relevant portion of this meeting will be closed to the public pursuant to the authority set forth in 5 U.S.C. 552b(c)(9)(B).

Sallie McDonald,

Deputy Manager, National Communications System.

[FR Doc. 07–1217 Filed 3–12–07; 2:43 pm]

BILLING CODE 4410–10–P

DEPARTMENT OF HOMELAND SECURITY

Bureau of Customs and Border Protection

Proposed Collection; Comment Request Regulations Relating to Recordation and Enforcement of Trademarks and Copyrights

ACTION: Notice and request for comments.

SUMMARY: As part of its continuing effort to reduce paperwork and respondent burden, Bureau of Customs and Border Protection (CBP) invites the general public and other Federal agencies to comment on an information collection requirement concerning the Regulations Relating to Recordation and Enforcement of Trademarks and Copyrights (Part 133 of the CBP Regulations). This request for comment is being made pursuant to the Paperwork Reduction Act of 1995 (Pub. L. 104–13; 44 U.S.C. 3505(c)(2)).

DATES: Written comments should be received on or before May 14, 2007, to be assured of consideration.

ADDRESSES: Direct all written comments to Bureau of Customs and Border Protection, Information Services Group, Attn.: Tracey Denning, 1300 Pennsylvania Avenue, NW., Room 3.2.C, Washington, DC 20229.

FOR FURTHER INFORMATION CONTACT: Requests for additional information should be directed to Bureau of Customs and Border Protection, Attn.: Tracey Denning, 1300 Pennsylvania Avenue NW., Room 3.2C, Washington, DC 20229, Tel. (202) 344–1429.

SUPPLEMENTARY INFORMATION: CBP invites the general public and other Federal agencies to comment on proposed and/or continuing information collections pursuant to the Paperwork Reduction Act of 1995 (Pub. L. 104–13; 44 U.S.C. 3505(c)(2)). The comments should address: (a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimates of the burden of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (d) ways to minimize the burden including the use of automated collection techniques or the use of other forms of information technology; and (e) estimates of capital or start-up costs and costs of operations, maintenance, and purchase of services to provide information. The comments that are submitted will be summarized and included in the CBP request for Office of Management and Budget (OMB) approval. All comments will become a matter of public record. In this document CBP is soliciting comments concerning the following information collection:

Title: Regulations Relating to Recordation and Enforcement of Trademarks and Copyrights (Part 133 of the CBP Regulations).

OMB Number: 1651–0123.

Form Number: None.

Abstract: Trademark and trade name owners and those claiming copyright protection must provide information sufficient to enable CBP officers to identify violative articles at the borders.

Current Actions: This submission is being submitted to extend the expiration date.

Type of Review: Extension (without change to the burden hours).

Affected Public: Businesses, Individuals.

Estimated Number of Respondents: 2,000.

Estimated Time per Respondent: 2 hours.

Estimated Total Annual Burden Hours: 4,000.

Estimated Total Annualized Cost on the Public: $380,000.

Dated: March 7, 2007.

Tracey Denning,

Agency Clearance Officer, Information Services Branch.

[FR Doc. E7–4764 Filed 3–14–07; 8:45 am]

BILLING CODE 9111–14–P

DEPARTMENT OF HOMELAND SECURITY

Bureau of Customs and Border Protection

Proposed Collection; Comment Request; Application—Alternative Inspection Services/FAST Commercial Driver Application

ACTION: Notice and request for comments.

SUMMARY: As part of its continuing effort to reduce paperwork and respondent burden, Bureau of Customs and Border Protection (CBP) invites the general public and other Federal agencies to comment on an information collection requirement concerning the Application—Alternative Inspection Services/FAST Commercial Driver Application. This request for comment is being made pursuant to the Paperwork Reduction Act of 1995 (Pub. L. 104–13; 44 U.S.C. 3505(c)(2)).

DATES: Written comments should be received on or before May 14, 2007, to be assured of consideration.

ADDRESSES: Direct all written comments to Bureau of Customs and Border Protection, Information Services Group, Attn.: Tracey Denning, 1300 Pennsylvania Avenue, NW., Room 3.2.C, Washington, DC 20229.

FOR FURTHER INFORMATION CONTACT: Requests for additional information should be directed to Bureau of Customs and Border Protection, Attn.: Tracey Denning, 1300 Pennsylvania Avenue NW., Room 3.2C, Washington, DC 20229, Tel. (202) 344–1429.

SUPPLEMENTARY INFORMATION: CBP invites the general public and other Federal agencies to comment on proposed and/or continuing information collections pursuant to the Paperwork Reduction Act of 1995 (Pub. L. 104–13; 44 U.S.C. 3505(c)(2)). The comments should address: (a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimates of the burden of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (d) ways to minimize the burden including the use of automated collection techniques or the use of other forms of information technology; and (e) estimates of capital or start-up costs and costs of operations, maintenance, and purchase of services to provide information. The comments that are submitted will be summarized and included in the CBP request for Office of Management and Budget (OMB) approval. All comments will become a matter of public record. In this document CBP is soliciting comments concerning the following information collection:

Title: Application—Alternative Inspection Services/FAST Commercial Driver Application.

OMB Number: 1651–0121.

Form Number: CBP Forms I–823 and 823F.

Abstract: The purpose of the Alternative Inspection Services and FAST Programs are to prescreen applicants and their vehicles in order to expedite travelers seeking admission to the United States. CBP plans to institute a web-based system for applicants to apply for Alternative Inspection Services and the FAST Program, and to phase out the paper versions of the I–823 and the 823F.

Current Actions: This submission is being submitted to extend the expiration date.

Type of Review: Extension (without change to the burden hours).

Affected Public: Businesses, Individuals.

Estimated Number of Respondents: 275,000.

Estimated Time per Respondent: 1 hour and 6 minutes.

Estimated Total Annual Burden Hours: 304,000.

Estimated Total Annualized Cost on the Public: $7,740,000.

Dated: March 7, 2007.

Tracey Denning,

Agency Clearance Officer, Information Services Branch.

[FR Doc. E7–4766 Filed 3–14–07; 8:45 am]

BILLING CODE 9111–14–P

DEPARTMENT OF HOMELAND SECURITY

Bureau of Customs and Border Protection

Automated Commercial Environment (ACE): Ability of Third Parties To Submit Manifest Information on Behalf of Truck Carriers Via the ACE Secure Data Portal in the Test of the ACE Truck Manifest System

AGENCY: Customs and Border Protection, Department of Homeland Security.

ACTION: General notice.

SUMMARY: This document announces that truck carriers participating in the ACE Truck Manifest Test and electing to use third parties to submit manifest information to the Bureau of Customs and Border Protection (CBP) via the Automated Commercial Environment (ACE) Secure Data Portal are no longer required to have ACE portal accounts. Thus, truck carriers without ACE portal accounts, while participating in the test of the ACE truck manifest system, may now use third parties (such as Customs brokers or other truck carriers) with ACE portal accounts to electronically transmit truck manifest information, via the ACE portal, on their behalf.

DATES: Truck carriers participating in the ACE Truck Manifest Test without ACE portal accounts may use third parties with ACE portal accounts to electronically transmit truck manifest information via the ACE portal, on their behalf, beginning March 15, 2007.

FOR FURTHER INFORMATION CONTACT: Mr. James Swanson, via e-mail at *james.d.swanson@dhs.gov*.

SUPPLEMENTARY INFORMATION:

Background

On February 4, 2004 and September 13, 2004, CBP published general notices in the **Federal Register** (69 FR 55167 and 69 FR 5360) announcing a test, in conjunction with the Federal Motor Carrier Safety Administration (FMCSA), allowing participating truck carriers to transmit electronic manifest data in ACE, including advance cargo information as required by section 343(a) of the Trade Act of 2002, as amended by the Maritime Transportation Security Act of 2002. The advance cargo information requirements are detailed in the final rule published in the **Federal Register** at 68 FR 68140 on December 5, 2003. Truck carriers participating in the test opened up Truck Carrier [Portal] Accounts which provided them with the ability to electronically transmit truck manifest data and obtain release of their cargo, crew, conveyances, and equipment via the ACE Portal or electronic data interchange (EDI) messaging.

In the September 13, 2004, notice, CBP stated that, in order to be eligible for participation in this test, a carrier must have:

1. Submitted an application (*i.e.*, statement of intent to establish an ACE [Portal] Account and to participate in the testing of electronic truck manifest functionality) as set forth in the February 4, 2004, notice;

2. Provided a Standard Carrier Alpha Code(s) (SCAC); and

3. Provided the name, address, and e-mail of a point of contact to receive further information.

In addition, the notice provided that participants intending to use the ACE Secure Data Portal as the means to file the manifest must submit a statement certifying the ability to connect to the Internet. Participants intending to use an EDI interface are required to first test their ability to send and receive electronic messages in either American National Standards Institute (ANSI) X12 or United Nations/Directories for Electronic Data Interchange for Administration, Commerce and Transport (UN/EDIFACT) format with CBP. The September 13, 2004, notice indicated that acceptance into this test does not guarantee eligibility for, or acceptance into, future technical tests.

Subsequently, in a **Federal Register** notice published on March 29, 2006 (71 FR 15756), CBP announced a change advising truck carriers that they were no longer required to open ACE Truck Carrier [Portal] Accounts to participate in the ACE test. Specifically, truck carriers were advised that they could elect to use a third party to submit electronic manifest information to CBP via EDI. Truck carriers participating in this fashion would not have access to operational data and would not receive status messages on ACE Accounts, nor would they have access to integrated Account data from multiple system sources. These truck carriers would be able to obtain release of their cargo, crew, conveyances, and equipment via EDI messaging back to the transmitter of the information. A truck carrier using a third party to transmit via EDI cargo, crew, conveyance and equipment information to CBP would be required to have a Standard Carrier Alpha Code (SCAC). Any truck carrier with a SCAC could arrange to have a third party transmit manifest information to CBP via EDI consistent with the requirements of the ACE Truck Manifest Test. Due to limited functionality available via the portal at that time, truck carriers were advised that if they elected to use a third party to transmit the truck manifest information to CBP via the ACE portal (rather than EDI), the truck carrier who is submitting that information to the third party (for transmission to CBP) would be required to have an ACE Truck Carrier Account as described in the February 4, 2004, notice. In clarification of the March 29, 2006, notice, if a truck carrier elects to use a third party to transmit the truck manifest information to CBP via EDI, the truck carrier would need to have a non-portal account.

Implementation

Since the publication of the March 29, 2006, notice, additional functionality has been deployed in the ACE portal so that a party with an ACE portal account now has the ability to transmit the manifest information via the ACE portal on behalf of other truck carriers. As a result, CBP announces in this document that truck carriers participating in the ACE Truck Manifest Test and electing to use a third party to submit manifest information to CBP via the ACE portal are no longer required to have ACE portal accounts as previously set forth in the March 29, 2006, notice.

By making this change, CBP is opening the ACE Truck Manifest Test to parties previously ineligible to participate. Truck carriers who do not have ACE portal accounts and who elect to use third parties to submit manifest information to CBP will no longer be restricted to electronic data interchange (EDI) messaging only.

Any party, whether a truck carrier or other entity, planning to transmit electronic truck manifest information on behalf of other truck carriers must establish or have established an ACE portal account. Interested parties must submit an application as set forth in the February 4, 2004, notice. Eligibility requirements specified in that notice include providing CBP with a Standard Carrier Alpha Code(s) (SCAC), if applicable, and providing the name, address, and e-mail of a point of contact to receive further information. Current portal truck carrier accounts wishing to transmit a manifest on behalf of another carrier will be able to do so through their existing accounts.

Carriers who use a third party to transmit manifest information will not have access to their manifest data unless they establish their own ACE Secure Data Portal Accounts. Truck carriers who elect to use the third party transmitter method will not receive status messages on ACE transactions. Those messages will be provided to the party transmitting the manifest information. Carriers without portal accounts who use a third party to transmit manifest information will need to have a non-portal account.

Previous Notices Continue To Be Applicable

All of the other aspects of the ACE Truck Manifest Test as set forth in the September 13, 2004, notice (69 FR 55167), as modified by the general notice published in the **Federal Register** (70 FR 13514) on March 21, 2005, continue to be applicable. The March 21, 2005, notice clarified that all relevant data elements are required to be submitted in the automated truck manifest submission. All of the aspects of the February 4, 2004, notice (69 FR 5360) also continue to be applicable, except as revised in this notice.

Dated: March 5, 2007.

Jayson P. Ahern,

Assistant Commissioner, Office of Field Operations.

[FR Doc. E7–4773 Filed 3–14–07; 8:45 am]

BILLING CODE 9111–14–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

Receipt of Applications for Permit

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Notice of receipt of applications for permit.

SUMMARY: The public is invited to comment on the following applications to conduct certain activities with endangered species and/or marine mammals.

DATES: Written data, comments or requests must be received by April 16, 2007.

ADDRESSES: Documents and other information submitted with these applications are available for review, subject to the requirements of the Privacy Act and Freedom of Information Act, by any party who submits a written request for a copy of such documents within 30 days of the date of publication of this notice to: U.S. Fish and Wildlife Service, Division of Management Authority, 4401 North Fairfax Drive, Room 700, Arlington, Virginia 22203; fax 703/358–2281.

FOR FURTHER INFORMATION CONTACT: Division of Management Authority, telephone 703/358–2104.

SUPPLEMENTARY INFORMATION:

Endangered Species

The public is invited to comment on the following applications for a permit to conduct certain activities with endangered species. This notice is provided pursuant to Section 10(c) of the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 *et seq.*). Written data, comments, or requests for copies of these complete applications should be submitted to the Director (address above).

Applicant: University of Texas at Austin, Austin, TX, PRT–140459

The applicant requests a permit to re-export biological samples collected in the wild in Mexico from aquatic box turtles (*Terrapene coahuila*) to the Universidad Nacional Autonoma de Mexico, Mexico, for scientific research.

Applicant: Wildlife Conservation Society, Bronx, NY, PRT–147321

The applicant requests a permit to import one male and one female captive-born lesser slow loris (*Nycticebus pygmaeus*) from the Calgary Zoo, Alberta, Canada for the purpose of enhancement of the species through captive propagation and conservation education.

Applicant: National Zoological Park, Washington, DC, PRT–134405

The applicant requests a permit to import biological samples from leatherback sea turtles (*Dermochelys coriacea*) collected in the wild in Gabon, for scientific research. This notification covers activities to be conducted by the applicant over a five-year period.

Applicant: Richard J. Lullo, Houston, TX, PRT–147381

The applicant requests a permit to import the sport-hunted trophy of one male bontebok (*Damaliscus pygargus pygargus*) culled from a captive herd maintained under the management program of the Republic of South Africa, for the purpose of enhancement of the survival of the species.

Applicant: Daniel H. Braman, III, Refugio, TX, PRT–147382

The applicant requests a permit to import the sport-hunted trophy of one male bontebok (*Damaliscus pygargus pygargus*) culled from a captive herd maintained under the management program of the Republic of South Africa, for the purpose of enhancement of the survival of the species.

Applicant: Shelby C. Fischer, Victoria, TX, PRT–147383

The applicant requests a permit to import the sport-hunted trophy of one male bontebok (*Damaliscus pygargus pygargus*) culled from a captive herd maintained under the management program of the Republic of South Africa, for the purpose of enhancement of the survival of the species.

Applicant: Stella W. Braman, Refugio, TX, PRT–147384

The applicant requests a permit to import the sport-hunted trophy of one male bontebok (*Damaliscus pygargus pygargus*) culled from a captive herd maintained under the management program of the Republic of South Africa, for the purpose of enhancement of the survival of the species.

Applicant: Jerry A. Jaeger, Plant City, FL, PRT–146588

The applicant requests a permit to import the sport-hunted trophy of one male bontebok (*Damaliscus pygargus pygargus*) culled from a captive herd maintained under the management program of the Republic of South Africa, for the purpose of enhancement of the survival of the species.

Marine Mammals

The public is invited to comment on the following applications for a permit to conduct certain activities with marine mammals. The applications were submitted to satisfy requirements of the Marine Mammal Protection Act of 1972, as amended (16 U.S.C. 1361 *et seq.*), and the regulations governing marine mammals (50 CFR part 18). Written data, comments, or requests for copies of the complete applications or requests for a public hearing on these applications should be submitted to the Director (address above). Anyone requesting a hearing should give specific reasons why a hearing would be appropriate. The holding of such a hearing is at the discretion of the Director.

Applicant: James R. Gabrick, Fountain City, WI, PRT–143422

The applicant requests a permit to import a polar bear (*Ursus maritimus*) sport hunted from the Western Hudson Bay polar bear population in Canada for personal, noncommercial use.

Applicant: Dennis C. Campbell, Dora, AL, PRT–145886

The applicant requests a permit to import a polar bear (*Ursus maritimus*) sport hunted from the Western Hudson Bay polar bear population in Canada for personal, noncommercial use.

Applicant: Manuel F. Camacho, Jr., Miami, FL, PRT–147469

The applicant requests a permit to import a polar bear (*Ursus maritimus*) sport hunted from the Lancaster Sound polar bear population in Canada for personal, noncommercial use.

Applicant: Dennis R. Kallash, Troy, MO, PRT–147415

The applicant requests a permit to import a polar bear (*Ursus maritimus*) sport hunted from the Northern Beaufort Sea polar bear population in Canada for personal, noncommercial use.

Dated: February 23, 2007.

Michael S. Moore,

Senior Permit Biologist, Branch of Permits, Division of Management Authority.

[FR Doc. E7–4763 Filed 3–14–07; 8:45 am]

BILLING CODE 4310–55–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

Issuance of Permits

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Notice of issuance of permits for endangered species and/or marine mammals.

SUMMARY: The following permits were issued.

ADDRESSES: Documents and other information submitted with these applications are available for review, subject to the requirements of the Privacy Act and Freedom of Information Act, by any party who submits a written request for a copy of such documents to: U.S. Fish and Wildlife Service, Division of Management Authority, 4401 North Fairfax Drive, Room 700, Arlington, Virginia 22203; fax 703/358–2281.

FOR FURTHER INFORMATION CONTACT: Division of Management Authority, telephone 703/358–2104.

SUPPLEMENTARY INFORMATION: Notice is hereby given that on the dates below, as authorized by the provisions of the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 *et seq.*), and/or the Marine Mammal Protection Act of 1972, as amended (16 U.S.C. 1361 *et seq.*), the Fish and Wildlife Service issued the requested permits subject to certain conditions set forth therein. For each permit for an endangered species, the Service found that (1) The application was filed in good faith, (2) the granted permit would not operate to the disadvantage of the endangered species, and (3) the granted permit would be consistent with the purposes and policy set forth in Section 2 of the Endangered Species Act of 1973, as amended.

Endangered Species

Permit No.	Applicant	Receipt of application **Federal Register** notice	Permit issuance date
134777	Kenneth E. Clifton	71 FR 76685; December 21, 2006	February 1, 2007.
138944	Anson M. K. Lum	71 FR 76685; December 21, 2006	February 1, 2007.
139635	Tommy E. Morrison	71 FR 76682; December 21, 2006	February 1, 2007.

Marine Mammals

Permit No.	Applicant	Receipt of application FEDERAL REGISTER Notice	Permit issuance date
133772	Richard H. Gebhard	71 FR 60561; October 13, 2006	February 5, 2007.
137715	Philip S. Majerus	71 FR 66187; November 13, 2006	February 5, 2007.
125179	Warren L. Strickland	71 FR 35692; June 21, 2006	January 4, 2007.
130142	Jerry L. Brenner	71 FR 76684; December 21, 2006	February 21, 2007.
137039	Kelly J. Powell	71 FR 76682; December 21, 2006	February 21, 2007.
138216	Michael J. Lenarduzzi	71 FR 76682; December 21, 2006	February 12, 2007.
141939	Philip M. Ripepi	72 FR 2539; January 19, 2007	February 21, 2007.

Dated: February 23, 2007.

Michael S. Moore,

Senior Permit Biologist, Branch of Permits, Division of Management Authority.

[FR Doc. E7–4761 Filed 3–14–07; 8:45 am]

BILLING CODE 4310–55–P

DEPARTMENT OF INTERIOR

U.S. Geological Survey

List of Programs Eligible for Inclusion in Fiscal Year 2007 Funding Agreements To Be Negotiated with Self-Governance Tribes

AGENCY: U.S. Geological Survey, Interior.

ACTION: Notice.

SUMMARY: This notice lists programs or portions of programs that are eligible for inclusion in fiscal year 2007 funding agreements with self-governance tribes and lists programmatic targets pursuant to section 405(c)(4) of the Tribal Self-Governance Act.

DATES: This notice expires on September 30, 2007.

ADDRESSES: Inquiries or comments regarding this notice may be directed to Sue Marcus, American Indian/Alaska Native Liaison, U.S. Geological Survey, 104 National Center, Reston, VA 20192.

SUPPLEMENTARY INFORMATION:

Background

Title II of the Indian Self-Determination Act amendments of 1994 (Pub. L. 103–413, the ‘‘Tribal Self-Governance Act’’ or the ‘‘Act’’) instituted a permanent self-governance program at the Department of the Interior (DOI). Under the self-governance program certain programs, services, functions, and activities, or portions thereof, in DOI bureaus other than the Bureau of Indian Affairs (BIA) are eligible to be planned, conducted, consolidated, and administered by a self-governance tribal government.

Under section 405(c) of the Act, the Secretary of the Interior (Secretary) is required to publish annually: (1) A list of non-BIA programs, services, functions, and activities, or portions thereof, that are eligible for inclusion in agreements negotiated under the self-governance program; and (2) programmatic targets for these bureaus.

Under the Act, two categories of non-BIA programs are eligible for self-governance funding agreements (AFAs):

(1) Under section 403(b)(2) of the Act, any non-BIA program, service, function or activity that is administered by COI that is ‘‘otherwise available to Indian tribes or Indians,’’ can be administered by a tribal government through a self-governance funding agreement. The DOI interprets this provision to authorize the inclusion of programs eligible for self-determination contracts under Title I of the Indian Self-Determination and Education Assistance Act (Pub. L. 93–638, as amended). Section 403(b)(2) also specifies ‘‘nothing in this subsection may be construed to provide any tribe with a preference with respect to the opportunity of the tribe to administer programs, services, functions and activities, or portions thereof, unless such preference is otherwise provided by law.’’

(2) Under section 403(c) of the Act, the Secretary may include other programs, services, functions, and activities or portions thereof that are of ‘‘special geographic, historical, or cultural significance’’ to a self-governance tribe.

Under section 403(k) of the Act, funding agreements cannot include programs, services, functions, or activities that are inherently Federal or where the statute establishing the existing program does not authorize the type of participation sought by the tribe. However, a tribe (or tribes) need not be identified in the authorizing statutes in order for a program or element to be included in a self-governance funding agreement. While general legal and policy guidance regarding what constitutes an inherently Federal function exists, we will determine whether a specific function is inherently Federal on a case-by-case basis considering the totality of circumstances.

Response to Comments

The DOI Office of Self-Governance requested comments on the proposed list on June 14, 2006. A number of editorial and technical changes were provided by DOI bureaus and incorporated into this Notice. While the Notice of June 14, 2006 illustrated all eligible non-BIA programs for DOI, this Notice is specific to the U.S. Geological Survey.

II. Eligible Non-BIA Programs of the U.S. Geological Survey

The U.S. Geological Survey (USGS) will consider for inclusion in funding agreements activities which, upon request of a self-governance tribe, USGS determines to be eligible under either sections 403(b)(2) or 403(c) of the Act. Tribes with an interest in such potential agreements are encouraged to being such discussions.

The mission of USGS is to collect, analyze, and provide information on biology, geology, hydrology, and geography that contributes to the wise management of the Nation’s natural resources and to the health, safety, and well-being of the American people. This information is usually publicly available and includes maps, data bases, and descriptions and analyses of the water, plants, animals, energy, and mineral resources, land surface, underlying geologic structure, and dynamic processes of the earth. The USGS does not manage lands or resources. Self-governance tribes may potentially assist USGS in the data acquisition and analysis components of its activities through a funding agreement.

For questions regarding self-governance contact Sue Marcus, American Indian/Alaska Native Liaison, U.S. Geological Survey, 104 National Center, Reston, VA 20192, telephone 703–648–4437, fax 703–648–4454, e-mail *smarcus@usgs.gov*.

III. Programmatic Targets

During fiscal year 2007, upon request of a self-governance tribe, the U.S. Geological Survey will negotiate

funding agreements for its eligible activities.

Dated: March 2, 2007.

Mark Limbaugh,

Assistant Secretary—Water and Science.

[FR Doc. 07–1211 Filed 3–14–07; 8:45 am]

BILLING CODE 4311–AM–M

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[CA–660–1430–ER–CACA–17905]

Notice of Availability of the Final Environmental Impact Report/ Environmental Impact Statement for the Southern California Edison Devers-Palo Verde No. 2 Transmission Line Project, California

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice of availability.

SUMMARY: In accordance with the National Environmental Policy Act of 1969 (NEPA), as amended (Pub. L. 91–190, 42 U.S.C. 4321–4347), and Title 40 CFR Parts 1500–1508, the Bureau of Land Management (BLM) hereby gives notice that the Final Environmental Impact Report/Environmental Impact Statement (EIR/EIS) for the Southern California Edison Company (SCE) Devers-Palo Verde No. 2 Transmission Line Project is available for public review and comment.

The BLM is the lead Federal agency for the preparation of the EIS in compliance with the requirements of NEPA. The California Public Utilities Commission (CPUC) is the lead State of California agency for the preparation of the EIR in compliance with the requirements of the California Environmental Quality Act. If the project is approved, BLM and CPUC would issue right-of-way grants to SCE.

DATES: The document will be available for public review and comment for 30 days following publication of a Notice of Availability (NOA) of this document in the **Federal Register** by the Environmental Protection Agency.

ADDRESSES: The EIR/EIS is available online at the BLM Web site: *http://www.blm.gov/ca/palmsprings.* Copies of the document can also be viewed at the BLM Palm Springs-South Coast Field Office, 690 West Garnet Ave., North Palm Springs, Calif. 92258, and at public libraries in Buckeye and Quartzite, Arizona, and Redlands, Banning, Beaumont, Calimesa, Cathedral City, Loma Linda, Riverside, Coachella, Colton, Desert Hot Springs, Grand Terrace, Indio, Mentone, Palm Desert, Palo Verde, Rancho Mirage, San Bernardino, and Yucaipa, California.

FOR FURTHER INFORMATION CONTACT: Greg Hill at (760) 251–4840 or e-mail: *gchill@ca.blm.gov.*

SUPPLEMENTARY INFORMATION: SCE is proposing to construct a new 230-mile long, 500-kilovolt (kV) electrical transmission line between its Devers Substation located near Palm Springs, California, and the Harquahala Generating Station switchyard, located near the Palo Verde Nuclear Generating Station west of Phoenix, Arizona. In addition, SCE is proposing to upgrade 48.2 miles of existing 230-kV transmission lines between the Devers Substation west to the San Bernardino and Vista Substations, located in the San Bernardino, California, vicinity. Together, the proposed 500-kV line and the 230-kV transmission facility upgrades are known as DPV2. The proposed route crosses public and private lands in Arizona and California. Portions of the proposed route cross Federal lands managed by the BLM and the U.S. Fish and Wildlife Service.

Construction of DPV2 would add 1,200 megawatts of transmission import capacity from the southwestern United States to California, which would reduce energy costs throughout California and enhance the reliability of California's energy supply through increased transmission infrastructure. The BLM identified a list of issues that this analysis addresses including the impacts of the proposed project on visual resources, agricultural lands, air quality, plant and animal species including special status species, cultural resources, and watersheds. Other issues identified by the BLM are impacts to the public in the form of noise, traffic, accidental release of hazardous materials, and impacts to urban, residential, and recreational areas.

Public participation hearings and workshops on the draft EIR/EIS were held in: Tonopah, Arizona, on June 6, 2006; Beaumont, California, on June 7, 2006; and Palm Desert, California, on June 8, 2006.

The BLM will prepare a Record of Decision (ROD) for the proposed project after a 30-day period following publication of the NOA.

Dated: December 11, 2006.

Gail Acheson,

Field Manager.

[FR Doc. E7–4759 Filed 3–14–07; 8:45 am]

BILLING CODE 4310–40– P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[OR–050–1020–MJ; HAG7–0083]

Notice of Public Meetings—John Day/ Snake Resource Advisory Council (RAC)

AGENCY: Bureau of Land Management (BLM), Prineville District, Interior.

ACTION: Notice of meetings.

SUMMARY: In accordance with the Federal Land Policy and Management Act and the Federal Advisory Committee Act of 1972, the Department of the Interior, BLM John Day Snake RAC will meet as indicated below:

The John Day/Snake RAC is scheduled to meet on April 3, 2007, at the Oxford Suites at 2400 S.W. Court Place, Pendleton, OR 97801. The meeting time will be from approximately 9 a.m. to 3 p.m. A public comment period will begin at 1 p.m., and end at 1:15 p.m. (Pacific Standard Time). The meeting may include such topics as off-highway vehicle and travel management, noxious weeds, planning, Sage grouse, and other matters as may reasonably come before the council.

Meeting Procedures: The meeting is open to the public. The public may present written comments to the RAC. Depending on the number of persons wishing to provide oral comments and agenda topics to be covered, the time to do so may be limited. Individuals who plan to attend and need special assistance such as sign language interpretation, tour transportation or other reasonable accommodations, should contact the BLM representative indicated below. For a copy of the information to be distributed to the RAC members, please submit a written request to the BLM Prineville District Office 10 days prior to the meeting.

FOR FURTHER INFORMATION CONTACT: Additional information concerning the John Day/Snake RAC may be obtained from Virginia Gibbons, BLM Public Affairs Specialist, Prineville District Office, 3050 N.E. Third Street, Prineville, Oregon 97754, (541) 416–6647 or e-mail *Virginia Gibbons@or.blm.gov.*

Dated: March 7, 2007.

Stephen R. Robertson,

Acting District Manager.

[FR Doc. E7–4673 Filed 3–14–07; 8:45 am]

BILLING CODE 4310–33–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[WY–923–1310–FI; WYW155744]

Wyoming: Notice of Proposed Reinstatement of Terminated Oil and Gas Lease

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice of proposed reinstatement of terminated oil and gas lease.

SUMMARY: Under the provisions of 30 U.S.C. 188(d) and (e), and 43 CFR 3108.2–3(a) and (b)(1), the Bureau of Land Management (BLM) received a petition for reinstatement from Missouri Basin Well Service Inc. for competitive oil and gas lease WYW155744 for land in Sheridan County, Wyoming. The petition was filed on time and was accompanied by all the rentals due since the date the lease terminated under the law.

FOR FURTHER INFORMATION CONTACT: Bureau of Land Management, Pamela J. Lewis, Chief, Branch of Fluid Minerals Adjudication, at (307) 775–6176.

SUPPLEMENTARY INFORMATION: The lessee has agreed to the amended lease terms for rentals and royalties at rates of $10.00 per acre or fraction thereof, per year and 16⅔ percent, respectively. The lessee has paid the required $500 administrative fee and $163.00 to reimburse the Department for the cost of this **Federal Register** notice. The lessee has met all the requirements for reinstatement of the lease as set out in Sections 31(d) and (e) of the Mineral Lands Leasing Act of 1920 (30 U.S.C. 188), and the Bureau of Land Management is proposing to reinstate lease WYW155744 effective December 1, 2006, under the original terms and conditions of the lease and the increased rental and royalty rates cited above. BLM has not issued a valid lease affecting the lands.

Pamela J. Lewis,

Chief, Branch of Fluid Minerals Adjudication.

[FR Doc. E7–4689 Filed 3–14–07; 8:45 am]

BILLING CODE 4310–22–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[AK–932–1430–ET; FF–84742]

Notice of Proposed Withdrawal Extension and Opportunity for Public Meeting; Alaska

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice.

SUMMARY: The U.S. Department of the Air Force (USAF) has filed an application with the Bureau of Land Management that proposes to extend the duration of Public Land Order (PLO) No. 6705 for an additional 20-year period. PLO No. 6705 withdrew approximately 3,630 acres of public land from surface entry and mining, to protect the USAF Beaver Creek Research Site. The land has been and will remain closed to mineral leasing. This notice also gives an opportunity to comment on the proposed action and to request a public meeting.

DATES: Comments and requests for a public meeting must be received by June 13, 2007.

ADDRESSES: Comments and meeting requests should be sent to the Alaska State Director, BLM Alaska State Office, 222 West 7th Avenue, No. 13, Anchorage, Alaska 99513–7599.

FOR FURTHER INFORMATION CONTACT: Terrie D. Evarts, BLM Alaska State Office, 907–271–5630.

SUPPLEMENTARY INFORMATION: The withdrawal created by PLO No. 6705 (54 FR 978, January 11, 1989), will expire on January 10, 2009, unless extended. The USAF has filed an application to extend PLO No. 6705 for an additional 20-year period to protect the integrity of the information being monitored by seismic equipment at the USAF Beaver Creek Research Site. This withdrawal comprises approximately 3,630 acres of public land located within:

Copper River Meridian

T.15 N., R. 19 E.,
Secs. 14, 15, secs. 20 to 29, inclusive,
Secs. 33 and 34, and is described in PLO No. 6705 (54 FR 978, January 11, 1989).

A complete description, along with all other records pertaining to the extension application, can be examined in the BLM Alaska State Office at the address shown above.

As extended, the withdrawal would not alter the applicability of those public land laws governing the use of land under lease, license, or permit or governing the disposal of the mineral or vegetative resources other than under the mining and mineral leasing laws.

The use of a right-of-way or interagency or cooperative agreement would not adequately protect the Federal investment in the Beaver Creek Research Site.

There are no suitable alternative sites available since the Beaver Creek Research Site is already constructed on the above-described public land.

No water rights would be needed to fulfill the purpose of the requested withdrawal extension.

For a period of 90 days from the date of publication of this notice, all persons who wish to submit comments, suggestions, or objections in connection with the proposed withdrawal extension may present their views in writing to the BLM State Director at the address indicated above. Individual respondents may request confidentiality. If you wish to withhold your name or address from public review or from disclosure under the Freedom of Information Act, you must state this prominently at the beginning of your comments. Such requests will be honored to the extent allowed by law. All submissions from organizations or businesses, and from individuals identifying themselves as representatives or officials of organizations or businesses, will be made available for public inspection in their entirety.

Notice is hereby given that an opportunity for a public meeting is afforded in connection with the proposed withdrawal extension. All interested parties who desire a public meeting for the purpose of being heard on the proposed withdrawal must submit a written request to the State Director at the address indicated above within 90 days from the publication of this notice. Upon determination by the authorized officer that a public meeting will be held, a notice of the time and place will be published in the **Federal Register** at least 30 days before the scheduled date of the meeting.

The withdrawal extension proposal will be processed in accordance with the regulations set forth in 43 CFR 2310.4 and subject to Section 810 of the Alaska National Interest Lands Conservation Act, 16 U.S.C. 3120 (2000).

(Authority: 43 CFR 2310.3–1(b)).

Dated: November 2, 2006.

Carolyn J. Spoon,

Chief, Branch of Lands and Realty.

Editorial Note: This document was received at the Office of the Federal Register on March 9, 2007.

[FR Doc. E7–4688 Filed 3–14–07; 8:45 am]

BILLING CODE 4310–JA–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[NV–030–1232–PM–NV14; Closure Notice No. NV–030–07–001]

Sand Mountain Recreation Area, NV, Motorized Travel Restrictions

AGENCY: Bureau of Land Management, Interior.

ACTION: Emergency Restriction on Motorized Use on Federal Lands, Churchill County, NV.

SUMMARY: Notice is hereby given that motorized travel is restricted on 3,985 acres on certain public lands located in and adjacent to Sand Mountain Recreation Area, Churchill County, Nevada. These restrictions are necessary because motorized travel is adversely affecting wildlife and BLM finds that in order to prevent further adverse effects to the habitat of the Sand Mountain blue butterfly (Euphilotes pallescens arenamontana) restricting motorized travel is required. These restrictions will remain in effect until such time as the Resource Management Plan has been updated to address the long-term management of the wildlife, cultural, vegetation and recreation resources in the area or until the Field Office Manager determines it is no longer needed. Resource damage has already taken place and the potential for additional adverse effects occurring as a result of unrestricted off-highway vehicle (OHV) use within this area is substantial and significant.

DATES: *Effective Date:* This restriction goes into effect immediately and will be verified upon publication in the **Federal Register**. It will remain in effect until the Manager, Carson City Field Office, determines it is no longer needed.

Authority: The authority for these restrictions is 43 CFR 8341.2, 8364.1, and 9268.3.

FOR FURTHER INFORMATION CONTACT: Donald T. Hicks, Field Office Manager, Carson City Field Office, 5665 Morgan Mill Road, Carson City, Nevada 89701. Telephone (775) 885–6000.

SUPPLEMENTARY INFORMATION: The Sand Mountain blue butterfly is known to occupy habitat only at Sand Mountain, Churchill County, Nevada, where it is completely dependent on its host plant, Kearney buckwheat (Eriogonum nummulare). Approximately 1,000 ac (405 ha) of dune shrub habitat remained in 2003, an estimated reduction of about 50 percent over the past 25 years. Moreover, much of this remaining habitat has been highly fragmented by over 200 miles (320 km) of OHV routes. The public lands affected by this order are located east of Fallon, Nevada and North of U.S. Highway 50, in Churchill County, Nevada and include certain public lands within:

Mt. Diablo Meridian

T. 17 N., R. 32 E.
Sec. 13, SW¼;
Sec. 14, S½S½;
Sec. 16, SE¼SE¼;
Sec. 20, SE¼;
Sec. 21, All;
Sec. 22, N½, SW¼;
Sec. 23, N½, SW¼, W½SE¼;
Sec. 24, W½NW¼;
Sec. 29, All;

And lands within Secs. 28, 32, and 33 of the Sand Mountain Recreation Area.

These lands are depicted on maps located in the Carson City Field Office and at maps posted at the Sand Mountain Recreation Area fee station and entrance area. Copies of these maps may be obtained from the Carson City Field Office. This restriction order applies to all forms of motorized vehicle use excluding (1) any emergency, law enforcement or other BLM vehicle while being used for emergency or administrative purposes, and (2) any vehicle whose use is expressly authorized in writing by the Manager, Carson City Field Office.

Penalty: Any person who fails to comply with the restriction order may be subject to imprisonment for not more than 12 months or a fine in accordance with the applicable provisions of 18 U.S.C. 3571, or both.

Dated: December 12, 2006.

Donald T. Hicks,

Manager, Carson City Field Office.

[FR Doc. E7–4687 Filed 3–14–07; 8:45 am]

BILLING CODE 4310–HC–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[ID–310–1220–PA–241A]

Notice of Order Closing Public Lands to Human Entry, Idaho

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice.

SUMMARY: To protect fragile, wintering mule deer, the Bureau of Land Management (BLM) is closing to human entry seasonally, during each of three consecutive years starting in 2007, certain public lands near the South Fork of the Snake River, east of Heise, Idaho. Also, BLM will be considering a permanent, seasonal closure to protect wintering mule deer herds.

DATES: The closure for the winter of 2007–2008 will take effect on December 1, 2007. Closures in 2008 and 2009 will take effect on December 1 of each year, respectively. Closures will end on April 30 of the following year, unless sooner terminated by the BLM authorized officer.

ADDRESSES: The address of the BLM Authorized Officer is: Field Manager, Upper Snake Field Office (USFO), 1405 Hollipark Drive, Idaho Falls, Idaho 83401.

FOR FURTHER INFORMATION CONTACT: Monica Zimmerman, BLM Outdoor Recreation Planner, (208) 524–7543; or Theresa Mathis, BLM Wildlife Biologist, (208) 524–7547.

SUPPLEMENTARY INFORMATION: While monitoring the progress of wintering wildlife in February of 2006, field personnel of the Idaho Department of Fish and Game (IDFG), Region 6 office in Idaho Falls, became aware of an increase in mule deer fawn and adult mortality rates due to recent cold temperatures and increasing human disturbances. The IDFG, therefore, requested that BLM order the closure to human entry seasonally, during 2006–2007, 2007–2008 and 2008–2009, of public lands in the Stinking Springs and Wolf Flat areas near the South Fork of the Snake River, east of Heise, Idaho. Closure dates are as stated above. The purpose of the closures is to prevent undue and unnecessary disturbance and harm to mule deer herds and other big game populations migrating to crucial winter range habitat. This initiative is being implemented in partnership with the IDFG Region 6 office. The pertinent BLM case file is available for public review in the USFO office at the address stated above. The authority for the requested closures is 43 CFR 8364.1(a), which states ''to protect persons, property, and public lands and resources, the authorized officer may issue an order to close or restrict use of designated public lands.'' This notice identifies by legal land description the precise areas that are closed to human entry.

Subject to valid existing rights, it is hereby ordered as follows:

Stinking Springs

Effective immediately, BLM-administered public lands located in the Stinking Springs area north of the South Fork of the Snake River near Heise, Idaho, described below, are closed to human entry within the dates specified above in this notice. Excepted from this closure order are entries for administrative use by BLM and use by BLM permittees, IDFG Conservation

Officers, and local law enforcement, as required. The Stinking Springs Trail will remain open from May 1 to November 30 of each year. The Stinking Springs area is a crucial wildlife area lying northeast of Idaho Falls, Idaho. The area is bounded generally by the South Fork of the Snake River on the south and west, and the Kelly Canyon Road and Targhee National Forest on the north and east. The legal description of the subject lands is as follows:

Boise Meridian, Idaho

T. 4 N., R. 41 E.,
Sec. 32, SE¼, SE¼ NE¼, and lands east of the Kelly Canyon Road in the NE¼ NE¼, NW¼NE¼, SW¼ NE¼, NE¼ SW¼;
Sec. 33, All.
T. 3 N., R. 41 E.,
Sec. 2, SW¼;
Sec. 3, All;
Sec. 4, SE¼, SE¼ SW¼, NE¼ SW¼, NW¼ SW¼;
Sec. 5, NW¼ NE¼;
Sec. 8, Lots 6 and 8;
Sec. 9, Lots 2 and 3, NE¼, NW¼, SE¼, NE¼ SW¼;
Sec. 10, NW¼, SW¼, NE¼ NE¼, NW¼ NE¼, SW¼ NE¼;
Sec. 11, Lot 2, N½ NW¼;
Sec. 15, Lots 7 and 8, NW¼ NW¼;
Sec. 16, Lots 5 and 6.

South Fork of the Snake River (Wolf Flat)

Effective immediately, BLM-administered public lands located in the Stinking Springs area north of the South Fork of the Snake River near Heise, Idaho, described below, are closed to human entry within the dates specified above in this notice. Excepted from this closure order are entries for administrative use by BLM and use by BLM permittees, IDFG Conservation Officers, and local law enforcement, as required. The legal description of the subject lands is as follows:

Wolf Flat: Those portions of the following described lands lying north of Heise Road, adjacent to the South Fork Snake River, in the following areas:

Boise Meridian, Idaho

T. 3 N., R. 41 E.,
Sec. 10, Lots 1 and 2;
Sec. 11, Lots 3 and 4;
Sec. 15, Lot 6.

Authority

This emergency closure notice is issued under the authority of 43 CFR 8364.1(c), 8341.2 and 9268.3. Violations of this closure are punishable by a fine not to exceed $1,000 or imprisonment not to exceed 12 months. Persons who are administratively exempt from the closure include any Federal, State, or local officer or employee acting within the scope of their duties, members of any organized rescue or fire-fighting force in the performance of an official duty, or any person holding written permission from the BLM.

Please be further advised that BLM will be considering a permanent, annual, seasonal closure to protect wintering mule deer herds on a long-term basis. This proposal and its potential environmental effects will be studied through a public process and environmental analysis conducted in accordance with NEPA.

Wendy Reynolds,
Upper Snake Field Manager.
[FR Doc. E7–4690 Filed 3–14–07; 8:45 am]
BILLING CODE 4310–GG–P

DEPARTMENT OF THE INTERIOR

National Park Service

Notice of Inventory Completion: Cosumnes River College, Los Rios Community College District, Sacramento, CA

AGENCY: National Park Service, Interior.
ACTION: Notice.

Notice is here given in accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), 25 U.S.C. 3003, of the completion of an inventory of human remains in the possession of Cosumnes River College, Los Rios Community College District, Sacramento, CA. The human remains were removed from Sacramento County, CA.

This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA, 25 U.S.C. 3003 (d)(3). The determinations in this notice are the sole responsibility of the museum, institution, or Federal agency that has control of the Native American human remains. The National Park Service is not responsible for the determinations in this notice.

A detailed assessment of the human remains was made by Cosumnes River College professional staff in consultation with representatives of the Ione Band of Miwok Indians of California.

In the 1920s, human remains representing a minimum of two individuals were removed from the Gallup Farm in Wilton, Sacramento County, CA, by the daughter of the landowner, Bernice Gallup. In 1974, the human remains were given to David Abrams, professor of Anthropology, Cosumnes River College. The human remains were in Professor Abram's personal possession until his death in 2004. In September 2006, Professor Abram's widow donated the human remains to Cosumnes River College. No known individuals were identified. No associated funerary objects are present.

According to museum records, the Gallup Farm was a known Miwok burial ground and was traditionally and historically the aboriginal land of the Ione Miwok. A forensic analysis of the human remains was conducted in October 2006. Dental wear patterns are consistent with known Miwok remains. Consultation with a representative of the Ione Band of Miwok Indians of California confirmed the identification of the human remains as Miwok. Based on museum records, donor statements, osteological evidence, and geographical information the Cosumnes River College officials reasonably believe that the human remains are Native American dating from before 1920, and are Ione Miwok. Descendants of the Ione Miwok are members of the Ione Band of Miwok Indians of California.

Officials of the Cosumnes River College have determined that, pursuant to 25 U.S.C. 3001 (9–10), the human remains described above represent the physical remains of two individuals of Native American ancestry. Officials of the Cosumnes River College also have determined that, pursuant to 25 U.S.C. 3001 (2), there is a relationship of shared group identity that can be reasonably traced between the Native American human remains and the Ione Band of Miwok Indians of California.

Representatives of any other Indian tribe that believes itself to be culturally affiliated with the human remains should contact William Karns, Vice-President of Instruction, Cosumnes River College, 8401 Center Parkway, Sacramento, CA 95823, telephone (916) 691–7326, before April 16, 2007. Repatriation of the human remains to the Ione Band of Miwok Indians of California may proceed after that date if no additional claimants come forward.

Cosumnes River College is responsible for notifying the Buena Vista Rancheria of Me-Wuk Indians of California; California Valley Miwok Tribe, California; Cher-Ae Heights Indian Community of the Trinidad Rancheria, California; Chicken Ranch Rancheria of Me-Wuk Indians of California; Federated Indians of Graton Rancheria, California; Ione Band of Miwok Indians of California; Jackson Rancheria of Me-Wuk Indians of California; Picayune Rancheria of Chukchansi Indians of California; Santa Rosa Indian Community of the Santa Rosa Rancheria, California; Shingle Springs Band of Miwok Indians, Shingle Springs Rancheria (Verona Tract), California; Table Mountain Rancheria of

California; Tule River Indian Tribe of the Tule River Reservation, California; Tuolumne Band of Me-Wuk Indians of the Tuolumne Rancheria of California; and United Auburn Indian Community of the Auburn Rancheria of California that this notice has been published.

Dated: February 13, 2007

Sherry Hutt,

Manager, National NAGPRA Program.

[FR Doc. E7–4731 Filed 3–14–07; 8:45 am]

BILLING CODE 4312–50–S

DEPARTMENT OF THE INTERIOR

National Park Service

Notice of Inventory Completion: U.S. Department of Agriculture, Forest Service, Tongass National Forest, Juneau, AK

AGENCY: National Park Service, Interior.

ACTION: Notice.

Notice is here given in accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), 25 U.S.C. 3003, of the completion of an inventory of human remains and associated funerary objects in the possession of the U.S. Department of Agriculture, Forest Service, Tongass National Forest, Juneau, AK. The human remains and associated funerary objects were removed from Admiralty Island National Monument in southeast Alaska.

This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA, 25 U.S.C. 3003 (d)(3). The determinations in this notice are the sole responsibility of the museum, institution, or Federal agency that has control of the Native American human remains and associated funerary objects. The National Park Service is not responsible for the determinations in this notice.

A detailed assessment of the human remains was made by the U.S. Department of Agriculture, Forest Service professional staff in consultation with representatives of the Angoon Community Association; Central Council of the Tlingit & Haida Indian Tribes; Kake Tribal Corporation; Kootznoowoo Incorporated; Organized Village of Kake; Sealaska Corporation; Shee Atika Inc.; and Sitka Tribe of Alaska. The U.S. Department of Agriculture, Forest Service also consulted with the Alaska Native Brotherhood and Sisterhood Camps in Angoon, Kake and Sitka, non-federally recognized Indian groups.

In August 1989, human remains representing a minimum of 18 individuals were removed from the Wilson Cove Rockshelter site, southwest Admiralty Island, AK, by Forest Service archeologists. No known individuals have been identified. The four associated funerary objects are four wood planks.

The Wilson Cove Rockshelter site is divided into three sites called Rockshelter 1, 2, and 3. The four wood planks are believed to have been part of a bentwood box associated with the human remains at Rockshelter 3. Radiocarbon dates from charcoal and shell from Rockshelter 1 were 755 B.C. - 200 B.C. and 40 B.C - A.D. 230. A radiocarbon date for Rockshelter 3 was 390 B.C. - A.D. 90.

A professional physical anthropologist analyzed the human remains from all three sites and determined they are Native American. Ethnographic information and archeological data indicate that the Wilson Cove Rockshelter site is within the traditional territory of the Angoon Tlingit. Oral traditions of the Angoon Tlingit confirm their affiliation with this site. Descendants of the Angoon Tlingit are members of Kootznoowoo Incorporated.

Officials of the U.S. Department of Agriculture, Forest Service have determined that, pursuant to 25 U.S.C. 3001 (9–10), the human remains described above represent the physical remains of 18 individuals of Native American ancestry. Officials of the U.S. Department of Agriculture, Forest Service also have determined that, pursuant to 25 U.S.C. 3001 (3)(A), the four objects described above are reasonably believed to have been placed with or near individual human remains at the time of death or later as part of the death rite or ceremony. Lastly, officials of the U.S. Department of Agriculture, Forest Service have determined that, pursuant to 25 U.S.C. 3001 (2), there is a relationship of shared group identity that can be reasonably traced between the Native American human remains and associated funerary objects and Kootznoowoo Incorporated.

Representatives of any other Indian tribe that believes itself to be culturally affiliated with the human remains and associated funerary objects should contact Forrest Cole, Forest Supervisor, Tongass National Forest, Federal Building, Ketchikan, AK 99901–6591, telephone (907) 225–3101, before April 16, 2007. Repatriation of the human remains and associated funerary objects to Kootznoowoo Incorporated may proceed after that date if no additional claimants come forward.

The U.S. Department of Agriculture, Forest Service is responsible for notifying the Angoon Community Association; Central Council of the Tlingit & Haida Indian Tribes; Kake Tribal Corporation; Kootznoowoo Incorporated; Organized Village of Kake; Sealaska Corporation; Shee Atika Inc.; Sitka Tribe of Alaska; and Alaska Native Brotherhood and Sisterhood Camps in Angoon, Kake and Sitka, non-federally recognized Indian groups, that this notice has been published.

Dated: February 13, 2007

Sherry Hutt,

Manager, National NAGPRA Program.

[FR Doc. E7–4730 Filed 3–14–07; 8:45 am]

BILLING CODE 4312–50–S

DEPARTMENT OF THE INTERIOR

National Park Service

Notice of Inventory Completion: U.S. Department of the Interior, National Park Service, Fort Union National Monument, Watrous, NM

AGENCY: National Park Service, Interior.

ACTION: Notice.

Notice is here given in accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), 25 U.S.C. 3003, of the completion of an inventory of human remains and associated funerary objects in the possession and control of the U.S. Department of the Interior, National Park Service, Fort Union National Monument, Watrous, NM. The human remains and cultural items were removed from an area near the fort in Mora County, NM.

This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA, 25 U.S.C. 3003 (d)(3). The determinations in this notice are the sole responsibility of the superintendent, Fort Union National Monument.

A detailed assessment of the human remains and associated funerary objects was made by Fort Union National Monument professional staff in consultation with representatives of the Arapaho Tribe of the Wind River Reservation, Wyoming; Comanche Nation, Oklahoma; Fort McDowell Yavapai Nation, Arizona; Jicarilla Apache Nation, New Mexico; Mescalero Apache Tribe of the Mescalero Reservation, New Mexico; Navajo Nation, Arizona, New Mexico & Utah; and Ute Mountain Tribe of the Ute Mountain Reservation, Colorado, New Mexico & Utah.

The Apache Tribe of Oklahoma; Cheyenne-Arapaho Tribes of Oklahoma; Fort Sill Apache Tribe of Oklahoma; Kiowa Indian Tribe of Oklahoma; Northern Cheyenne Tribe of the Northern Cheyenne Indian Reservation, Montana; San Carlos Apache Tribe of the San Carlos Reservation, Arizona; Southern Ute Indian Tribe of the Southern Ute Reservation, Colorado; Tonto Apache Tribe of Arizona; Ute Indian Tribe of the Uintah & Ouray Reservation, Utah; White Mountain Apache Tribe of the Fort Apache Reservation, Arizona; and Yavapai-Apache Nation of the Camp Verde Indian Reservation, Arizona were contacted for consultation purposes but did not attend the consultation meetings.

In 1958, human remains representing a minimum of four individuals were removed from Fort Union National Monument in Mora County, NM, during the construction of park housing. No known individuals were identified. All but 10 of the approximately 40 artifacts found with the human remains have been lost or have disintegrated. The 10 surviving associated funerary objects are 1 turquoise bead, 1 shell bead, 1 fragmentary shell bead, 1 leather fragment, 2 pieces of fabric, 1 fragment of bark, 2 fragments of rotted leather, and 1 fragment of material that is either rotted leather or metal. Most of the objects are only identifiable by consulting the park's museum catalog cards.

Based on skeletal and artifactual analysis, it appears that the four men were beaten, shot, dragged using leather straps found with the bodies, and buried in a grave approximately 18 inches deep. The mass grave was located immediately adjacent to where the Santa Fe Trail entered Fort Union. The men were laid out in an orderly fashion, oriented to the southeast. Most items of value appear to have been removed from the bodies. Buttons and the caliber of bullets used to kill the men indicate that the murders took place sometime between the years of 1863 and 1872. At the request of officials of Fort Union National Monument, a cultural affiliation report was prepared in 2006 in an effort to determine cultural affiliation by examining all available evidence.

Officials of Fort Union National Monument have determined that, pursuant to 25 U.S.C. 3001 (9–10), the human remains described above represent the physical remains of four individuals of Native American ancestry. Officials of Fort Union National Monument also have determined that, pursuant to 25 U.S.C. 3001 (3)(A), the ten objects described above are reasonably believed to have been placed with or near individual human remains at the time of death or later as part of the death rite or ceremony. Lastly, officials of Fort Union National Monument have determined that, pursuant to 25 U.S.C. 3001 (2), a relationship of shared group identity cannot reasonably be traced between the Native American human remains and associated funerary objects and any present-day Indian tribe.

The Native American Graves Protection and Repatriation Review Committee (Review Committee) is responsible for recommending specific actions for disposition of culturally unidentifiable human remains. In October 2006, Fort Union National Monument requested that the Review Committee recommend repatriation of the four culturally unidentifiable human remains and ten associated funerary objects to the Jicarilla Apache Nation, New Mexico and Ute Mountain Tribe of the Ute Mountain Reservation, Colorado, New Mexico & Utah as co-claimants because the human remains and cultural items were found within the tribes' aboriginal and historical territory. The Review Committee considered the proposal at its November 2006 meeting, and recommended disposition of the human remains and associated funerary objects to the Jicarilla Apache Nation, New Mexico and Ute Mountain Tribe of the Ute Mountain Reservation, Colorado, New Mexico & Utah. The National Park Service intends to convey the ten associated funerary objects to the tribes pursuant to 16 U.S.C. 18f–2.

A December 12, 2006, letter from the Designated Federal Official, writing on behalf of the Secretary of the Interior, recommended disposition of the physical remains of four culturally unidentifiable individuals and ten associated funerary objects to the Jicarilla Apache Nation, New Mexico and Ute Mountain Tribe of the Ute Mountain Reservation, Colorado, New Mexico & Utah contingent on the publication of a Notice of Inventory Completion in the **Federal Register**. This notice fulfills that requirement.

Representatives of any other Indian tribe that believes itself to be culturally affiliated with the human remains and associated funerary objects should contact Marie Frias Sauter, superintendent, Fort Union National Monument, P.O. Box 127, Watrous, NM 87753, telephone (505) 425–8025, before April 16, 2007. Disposition of the human remains and associated funerary objects to the Jicarilla Apache Nation, New Mexico and Ute Mountain Tribe of the Ute Mountain Reservation, Colorado, New Mexico & Utah may proceed after that date if no additional claimants come forward.

Fort Union National Monument is responsible for notifying the Arapaho Tribe of the Wind River Reservation, Wyoming; Comanche Nation, Oklahoma; Fort McDowell Yavapai Nation, Arizona; Jicarilla Apache Nation, New Mexico; Mescalero Apache Tribe of the Mescalero Reservation, New Mexico; Navajo Nation, Arizona, New Mexico & Utah; and Ute Mountain Tribe of the Ute Mountain Reservation, Colorado, New Mexico & Utah that this notice has been published.

Dated: February 8, 2007.

Sherry Hutt,

Manager, National NAGPRA Program.

[FR Doc. E7–4728 Filed 3–14–07; 8:45 am]

BILLING CODE 4312–50–S

DEPARTMENT OF THE INTERIOR

National Park Service

Notice of Inventory Completion: Peabody Museum of Archaeology and Ethnology, Harvard University, Cambridge, MA

AGENCY: National Park Service, Interior.

ACTION: Notice.

Notice is here given in accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), 25 U.S.C. 3003, of the completion of an inventory of human remains in the possession of Peabody Museum of Archaeology and Ethnology, Harvard University, Cambridge, MA. The human remains were removed from Plymouth County, MA.

This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA, 25 U.S.C. 3003 (d)(3). The determinations in this notice are the sole responsibility of the museum, institution, or Federal agency that has control of the Native American human remains. The National Park Service is not responsible for the determinations in this notice.

A detailed assessment of the human remains was made by Peabody Museum of Archaeology and Ethnology professional staff in consultation with representatives of the Wampanoag Repatriation Confederation on behalf of the Wampanoag Tribe of Gay Head (Aquinnah) of Massachusetts; Assonet Band of the Wampanoag Nation, a non-federally recognized Indian group; and Mashpee Wampanoag Indian Tribe, a non-federally recognized Indian group.

Between 1890 and 1900, human remains representing a minimum of two individuals were removed from Watson's Hill, south side of Town Brook, in Plymouth, Plymouth County, MA, by the Douglas family while the family was digging a cellar for their house. The human remains were transferred to Dr. George H. Jackson of Plymouth at an unknown date. In 1939, the human remains were donated to the Peabody Museum of Archaeology and Ethnology by Dr. Jackson through the Pilgrim Society of Plymouth. No known individuals were identified. No associated funerary objects are present.

Osteological characteristics indicate that the individuals are Native American. The interments most likely date to the Late Woodland period or later (post-A.D. 1000). Historical documentation, as well as information from the Pilgrim Society, describes Watson's Hill as a known Late Woodland (A.D. 1000–1500) and Historic/Contact period (post-A.D. 1500) Native American site. Oral tradition and historical documentation also indicate that Plymouth is within the aboriginal and historic homeland of the Wampanoag Nation. The present-day tribes that are most closely affiliated with the Wampanoag Nation are the Wampanoag Tribe of Gay Head (Aquinnah) of Massachusetts; Assonet Band of the Wampanoag Nation, a non-federally recognized Indian group; and Mashpee Wampanoag Indian Tribe, a non-federally recognized Indian group.

Officials of the Peabody Museum of Archaeology and Ethnology have determined that, pursuant to 25 U.S.C. 3001 (9–10), the human remains described above represent the physical remains of two individuals of Native American ancestry. Officials of the Peabody Museum of Archaeology and Ethnology also have determined that, pursuant to 25 U.S.C. 3001 (2), there is a relationship of shared group identity that can be reasonably traced between the Native American human remains and the Wampanoag Tribe of Gay Head (Aquinnah) of Massachusetts. Furthermore, officials of the Peabody Museum of Archaeology and Ethnology have determined that there is a cultural relationship between the human remains and the Assonet Band of the Wampanoag Nation, a non-federally recognized Indian group, and Mashpee Wampanoag Indian Tribe, a non-federally recognized Indian group.

Representatives of any other Indian tribe that believes itself to be culturally affiliated with the human remains should contact Patricia Capone, Repatriation Coordinator, Peabody Museum of Archaeology and Ethnology, Harvard University, 11 Divinity Ave., Cambridge, MA 02138, telephone (617) 496–3702, before April 16, 2007. Repatriation of the human remains to the Wampanoag Repatriation Confederation on behalf of the Wampanoag Tribe of Gay Head (Aquinnah) of Massachusetts; Assonet Band of the Wampanoag Nation, a non-federally recognized Indian group; and Mashpee Wampanoag Indian Tribe, a non-federally recognized Indian group may proceed after that date if no additional claimants come forward.

The Peabody Museum of Archaeology and Ethnology is responsible for notifying the Wampanoag Repatriation Confederation, Wampanoag Tribe of Gay Head (Aquinnah) of Massachusetts; Assonet Band of the Wampanoag Nation, a non-federally recognized Indian group; and Mashpee Wampanoag Indian Tribe, a non-federally recognized Indian group that this notice has been published.

Dated: January 30, 2007

Sherry Hutt,

National NAGPRA Program.

[FR Doc. E7–4727 Filed 3–14–07; 8:45 am]

BILLING CODE 4312–50–S

DEPARTMENT OF THE INTERIOR

National Park Service

Notice of Inventory Completion: Thomas Burke Memorial Washington State Museum, University of Washington, Seattle, WA

AGENCY: National Park Service, Interior.

ACTION: Notice.

Notice is here given in accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), 25 U.S.C. 3003, of the completion of an inventory of human remains in the possession of the Thomas Burke Memorial Washington State Museum (Burke Museum), University of Washington, Seattle, WA. The human remains were removed from Okanogan County, WA.

This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA, 25 U.S.C. 3003 (d)(3). The determinations in this notice are the sole responsibility of the museum, institution, or Federal agency that has control of the Native American human remains. The National Park Service is not responsible for the determinations in this notice.

A detailed assessment of the human remains was made by Burke Museum professional staff in consultation with representatives of the Confederated Tribes of the Colville Reservation, Washington.

In 1908, human remains representing a minimum of one individual were removed from Winthrop in Okanogan County, WA, by CPT Frank Lord. In 1910, the human remains were received from Captain Lord and accessioned by the Burke Museum (Burke Accn. No. 242). No known individual was identified. No associated funerary objects are present.

The human remains had previously been identified non- Native American. However, after further review, the preponderance of the evidence identifies the human remains as Native American. The original donor identified the human remains as ''Indian''. The majority of the osteological evidence identified by physical anthropologists determined that the human remains are Native American.

According to early and late ethnographic documentation the Methow Tribe are the aboriginal occupants of the Winthrop area (Miller 1998; Mooney 1896; Ray 1936; Spier 1936). The Colville Reservation was established by Executive Order in 1872 for Methow Tribe and other tribes. The Moses Columbia Reservation was later established in 1879 and also included members of the Methow Tribe. In 1886, the Moses Columbia Reservation was disbanded and the residents were moved to the Colville Reservation. Descendants of the Methow Tribe are members of the Confederated Tribes of the Colville Reservation, Washington.

Officials of the Burke Museum have determined that, pursuant to 25 U.S.C. 3001 (9–10), the human remains described above represent the physical remains of one individual of Native American ancestry. Officials of the Burke Museum also have determined that, pursuant to 25 U.S.C. 3001 (2), there is a relationship of shared group identity that can be reasonably traced between the Native American human remains and the Confederated Tribes of the Colville Reservation, Washington.

Representatives of any other Indian tribe that believes itself to be culturally affiliated with the human remains should contact Dr. Peter Lape, Burke Museum, University of Washington, Box 353010, Seattle, WA 98195–3010, telephone (206) 685–2282, before April 16, 2007. Repatriation of the human remains to the Confederated Tribes of the Colville Reservation, Washington may proceed after that date if no additional claimants come forward.

The Burke Museum is responsible for notifying the Confederated Tribes of the Colville Reservation, Washington that this notice has been published.

Dated: January 26, 2007.

Sherry Hutt,

Manager, National NAGPRA Program.

[FR Doc. E7–4732 Filed 3–14–07; 8:45 am]

BILLING CODE 4312–50–S

DEPARTMENT OF THE INTERIOR

National Park Service

Notice of Intent to Repatriate Cultural Items: University of Colorado Museum, Boulder, CO

AGENCY: National Park Service, Interior.

ACTION: Notice.

Notice is here given in accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), 25 U.S.C. 3005, of the intent to repatriate cultural items in the possession of the University of Colorado Museum, Boulder, CO, that meet the definition of ''unassociated funerary objects'' under 25 U.S.C. 3001.

This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA, 25 U.S.C. 3003 (d)(3). The determinations in this notice are the sole responsibility of the museum, institution, or Federal agency that has control of the cultural items. The National Park Service is not responsible for the determinations in this notice.

Between 1954 and 1990, cultural items were legally excavated on private land near Yellow Jacket Pueblo (5MT5), Montezuma County, CO, by Dr. Joe Ben Wheat, during University of Colorado Museum sponsored archeological field schools. The excavated cultural items were collected from graves and legally transferred to the museum each season. The human remains were not collected due to deterioration or other circumstances. The 68 cultural items are 66 ceramic items (whole vessels, broken vessels, and sherd lots), 1 stone ax, and 1 bone awl.

The three habitation sites, identified on the National Register of Historic Places as the Joe Ben Wheat Site Complex, are at the head of Yellow Jacket Canyon to the west of Tatum Draw and southwest of the very large archeological site, Yellow Jacket Pueblo. The Yellow Jacket burials were predominantly single interments, appearing in a wide variety of locations, including abandoned rooms and kivas, storage pits, subfloor burial pits, extramural burial pits, and middens.

The habitation sites were occupied at various times during the Basketmaker III, Pueblo II, and Pueblo III periods, approximately A.D. 550 - 1250, with a temporary abandonment during the Pueblo I period, approximately A.D. 750 - 900. Based on the general continuity in the material culture and the architecture of these sites, it appears that the community that lived in this area had long-standing ties to the region and returned to sites even after migrations away from the locale that lasted more than one hundred years. However, by the late 13th century, both the Yellow Jacket sites and the nearby Mesa Verde region showed no evidence of human habitation. The sites are not used again until the 1920s when the locale was homesteaded and farmed.

The archeological evidence supports identification with Basketmaker and later Pueblo (Hisatsinom, Ancestral Puebloan, or Anasazi) cultures, which prehistorically occupied southwestern Colorado. Both Basketmaker and Pueblo occupations are represented in the archeology at the Yellow Jacket site. Archeologists have noted in the scientific literature the striking similarity between the technology and style of material culture of 13th century archeological sites in southwestern Colorado and the material culture remains of 14th century Puebloan sites in Arizona and New Mexico.

Oral-tradition evidence, which consists of migration stories, clan histories, and origin stories, was provided by representatives of the Hopi Tribe of Arizona; Navajo Nation, Arizona, New Mexico & Utah; Pueblo of Acoma, New Mexico; Pueblo of Isleta, New Mexico; Pueblo of Jemez, New Mexico; Pueblo of Laguna, New Mexico; Pueblo of Nambe, New Mexico; Pueblo of Pojoaque, New Mexico; Pueblo of San Ildefonso, New Mexico; Pueblo of San Juan, New Mexico; Pueblo of Santa Ana, New Mexico; Pueblo of Santa Clara, New Mexico; Pueblo of Taos, New Mexico; Pueblo of Tesuque, New Mexico; Pueblo of Ysleta del Sur, New Mexico; Pueblo of Zia, New Mexico; and Zuni Tribe of the Zuni Reservation, New Mexico. Folkloric evidence in the form of songs was provided by tribal representatives of the Pueblo of Acoma, New Mexico; Pueblo of Cochiti, New Mexico; Pueblo of Isleta, New Mexico; Pueblo of Nambe, New Mexico; and Pueblo of San Ildefonso, New Mexico.

Tribal representatives of the Pueblo of Acoma, New Mexico; Pueblo of Nambe, New Mexico; Pueblo of San Ildefonso, New Mexico; and Pueblo of Taos, New Mexico provided linguistic evidence rooted in place names. Pueblo of Cochiti, New Mexico; Pueblo of Nambe, New Mexico; Pueblo of San Ildefonso, New Mexico; and Pueblo of Santa Clara, New Mexico provided archeological evidence based on architecture and material culture of their shared relationship.

Archeological, historical and linguistic evidence presently points to Navajo migration to the Yellow Jacket and Monument Ruin area after A.D. 1300. During consultation, the Navajo Nation, Arizona, New Mexico & Utah emphasized their long presence in the Four Corners and their origin in this area, but there is not a preponderance of the evidence to support Navajo cultural affiliation.

Based on a preponderance of evidence, including oral tradition, folklore, linguistic, geographic, archeology, historical, and scientific studies, cultural affiliation can be traced between the 68 unassociated funerary objects and modern Puebloan peoples. Modern Puebloan peoples are members of the Hopi Tribe of Arizona; Pueblo of Acoma, New Mexico; Pueblo of Cochiti, New Mexico; Pueblo of Isleta, New Mexico; Pueblo of Jemez, New Mexico; Pueblo of Laguna, New Mexico; Pueblo of Nambe, New Mexico; Pueblo of Picuris, New Mexico; Pueblo of Pojoaque, New Mexico; Pueblo of San Felipe, New Mexico; Pueblo of San Ildefonso, New Mexico; Pueblo of San Juan, New Mexico; Pueblo of Sandia, New Mexico; Pueblo of Santa Ana, New Mexico; Pueblo of Santa Clara, New Mexico; Pueblo of Santo Domingo, New Mexico; Pueblo of Taos, New Mexico; Pueblo of Tesuque, New Mexico; Pueblo of Zia, New Mexico; Ysleta del Sur Pueblo of Texas; and Zuni Tribe of the Zuni Reservation, New Mexico.

Officials of the University of Colorado Museum have determined that, pursuant to 25 U.S.C. 3001 (3)(B), the 68 cultural items described above are reasonably believed to have been placed with or near individual human remains at the time of death or later as part of the death rite or ceremony and are believed, by a preponderance of the evidence, to have been removed from a specific burial site of an Native American individual. Officials of the University of Colorado Museum also have determined that, pursuant to 25 U.S.C. 3001 (2), there is a relationship of shared group identity that can be reasonably traced between the unassociated funerary objects and the Hopi Tribe of Arizona; Pueblo of Acoma, New Mexico; Pueblo of Cochiti, New Mexico; Pueblo of Isleta, New Mexico; Pueblo of Jemez, New Mexico; Pueblo of Laguna, New Mexico; Pueblo of Nambe, New Mexico; Pueblo of Picuris, New Mexico; Pueblo of Pojoaque, New Mexico; Pueblo of San Felipe, New Mexico; Pueblo of San Ildefonso, New Mexico; Pueblo of San Juan, New Mexico; Pueblo of Sandia,

New Mexico; Pueblo of Santa Ana, New Mexico; Pueblo of Santa Clara, New Mexico; Pueblo of Santo Domingo, New Mexico; Pueblo of Taos, New Mexico; Pueblo of Tesuque, New Mexico; Pueblo of Zia, New Mexico; Ysleta del Sur Pueblo of Texas; and Zuni Tribe of the Zuni Reservation, New Mexico.

Representatives of any other Indian tribe that believes itself to be culturally affiliated with the unassociated funerary objects should contact Stephen Lekson, Curator of Anthropology, University of Colorado Museum, Henderson Building, Campus Box 218, Boulder, CO 80309–0218, telephone (303) 492–6671, before April 16, 2007. Repatriation of the unassociated funerary objects to the Pueblo of Acoma, New Mexico may proceed after that date if no additional claimants come forward.

University of Colorado Museum is responsible for notifying the Hopi Tribe of Arizona; Navajo Nation, Arizona, New Mexico & Utah; Pueblo of Acoma, New Mexico; Pueblo of Cochiti, New Mexico; Pueblo of Isleta, New Mexico; Pueblo of Jemez, New Mexico; Pueblo of Laguna, New Mexico; Pueblo of Nambe, New Mexico; Pueblo of Picuris, New Mexico; Pueblo of Pojoaque, New Mexico; Pueblo of San Felipe, New Mexico; Pueblo of San Ildefonso, New Mexico; Pueblo of San Juan, New Mexico; Pueblo of Sandia, New Mexico; Pueblo of Santa Ana, New Mexico; Pueblo of Santa Clara, New Mexico; Pueblo of Santo Domingo, New Mexico; Pueblo of Taos, New Mexico; Pueblo of Tesuque, New Mexico; Pueblo of Zia, New Mexico; Southern Ute Indian Tribe of the Southern Ute Reservation, Colorado; Ute Mountain Tribe of the Ute Mountain Reservation, Colorado, New Mexico & Utah; Ysleta Del Sur Pueblo of Texas; and Zuni Tribe of the Zuni Reservation, New Mexico that this notice has been published.

Dated: February 2, 2007.

Sherry Hutt,

Manager, National NAGPRA Program.

[FR Doc. E7–4733 Filed 3–14–07; 8:45 am]

BILLING CODE 4312–50–S

DEPARTMENT OF THE INTERIOR

National Park Service

Notice of Intent to Repatriate Cultural Items: University of Kansas, Lawrence, KS

AGENCY: National Park Service, Interior.

ACTION: Notice.

Notice is here given in accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), 25 U.S.C. 3005, of the intent to repatriate cultural items in the possession of the University of Kansas, Lawrence, KS that meet the definitions of ‘‘sacred objects and ‘‘objects of cultural patrimony’’ under 25 U.S.C. 3001.

This notice is published as part of the National Park Service’s administrative responsibilities under NAGPRA, 25 U.S.C. 3003 (d)(3). The determinations in this notice are the sole responsibility of the museum, institution, or Federal agency that has control of the cultural items. The National Park Service is not responsible for the determinations in this notice.

The four cultural items are four Hopi ‘‘spirit friends’’ or Katsina masks (Matia, Hopak, Woe, and Mudhead). In 1966, Mrs. Agnese N. Haury purchased masks of the Hopi deities Matia, Hopak, and Woe at O’Reilly’s Plaza Art Galleries, Inc., in New York. Mrs. Haury donated the three Katsina masks to the University of Kansas in 1990. In 1992, the Karl Menninger Foundation donated a mask of the Hopi deity Mudhead to the University of Kansas. It is not known when or how Dr. Menninger acquired the Mudhead mask.

Representatives of the Hopi Tribe of Arizona, acting on behalf of the Katsinmomngwit (Hopi traditional religious leaders), have identified the four cultural items as being needed by traditional Hopi religious leaders for the practice of a traditional Native American religion by their present-day adherents. Representatives of the Hopi Tribe of Arizona also have identified the four cultural items as having ongoing historical, traditional, and cultural importance central to the culture itself, and the cultural items could not be alienated by any individual.

Officials of the University of Kansas have determined that, pursuant to 25 U.S.C. 3001 (3)(C), the four cultural items described above are specific ceremonial objects needed by traditional Native American religious leaders for the practice of traditional Native American religions by their present-day adherents. Officials of the University of Kansas also have determined that, pursuant to 25 U.S.C. 3001 (3)(D), the four cultural items described above have ongoing historical, traditional, or cultural importance central to the Native American group or culture itself, rather than property owned by an individual. Lastly, officials of the University of Kansas have determined that, pursuant to 25 U.S.C. 3001 (2), there is a relationship of shared group identity that can be reasonably traced between the sacred objects/objects of cultural patrimony and the Hopi Tribe of Arizona.

Representatives of any other Indian tribe that believes itself to be culturally affiliated with the sacred objects/objects of cultural patrimony should contact Thomas A. Foor, NAGPRA Coordinator, ARCC, University of Kansas, Spooner Hall, 1340 Jayhawk Blvd., Room 5B, Lawrence, KS 66045–7500, telephone (785) 766–5476, before April 16, 2007. Repatriation of the sacred objects/objects of cultural patrimony to the Hopi Tribe of Arizona may proceed after that date if no additional claimants come forward.

The University of Kansas is responsible for notifying the Hopi Tribe of Arizona that this notice has been published.

Dated: January 24, 2007.

Sherry Hutt,

Manager, National NAGPRA Program.

[FR Doc. E7–4726 Filed 3–14–07; 8:45 am]

BILLING CODE 4312–50–S

DEPARTMENT OF THE INTERIOR

Office of Surface Mining Reclamation and Enforcement

Notice of Proposed Information Collection for 1029–0057 and 1029–0087

AGENCY: Office of Surface Mining Reclamation and Enforcement.

ACTION: Notice and request for comments.

SUMMARY: In compliance with the Paperwork Reduction Act of 1995, the Office of Surface Mining Reclamation and Enforcement (OSM) is announcing its intention to request renewed approval for the collections of information for 30 CFR Part 882, Reclamation of private lands; and 30 CFR 886.23(b) and Form OSM–76, Abandoned Mine Land Problem Area Description form. The collections described below have been forwarded to the Office of Management and Budget (OMB) for review and comment. The information collection request describes the nature of the information collections and the expected burdens and costs.

DATES: OMB has up to 60 days to approve or disapprove the information collection but may respond after 30 days. Therefore, public comments should be submitted to OMB by April 16, 2007, in order to be assured of consideration.

ADDRESSES: Comments may be submitted to the Office of Information and Regulatory Affairs, Office of

Management and Budget, Department of the Interior Desk Officer, via e-mail at *OIRA_Docket@eop.gov,* or by facsimile to (202) 395–6566. Also, please send a copy of your comments to John A. Trelease, Office of Surface Mining Reclamation and Enforcement, 1951 Constitution Ave, NW., Room 202–SIB, Washington, DC 20240, or electronically to *jtreleas@osmre.gov.* Please reference 1029–0057 for Part 882 and 1029–0087 for the OSM–76 form in your submission.

FOR FURTHER INFORMATION CONTACT: To receive a copy of either information collection request contact John A. Trelease at (202) 208–2783, or electronically at *jtrelease@osmre.gov.*

SUPPLEMENTARY INFORMATION: The Office of Management and Budget (OMB) regulations at 5 CFR 1320, which implement provisions of the Paperwork Reduction Act of 1995 (Pub. L. 104–13), require that interested members of the public and affected agencies have an opportunity to comment on information collection and recordkeeping activities [see 5 CFR 1320.8(d)]. OSM has submitted requests to OMB to approve the collections of information for 30 CFR Part 882, Reclamation of private lands; and 30 CFR 886.23(b) and it's implementing Form OSM–76, Abandoned Mine Land Problem Area Description form. OSM is requesting a 3-year term of approval for these information collection activities.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for these collections of information are displayed in 30 CFR 882.10 for Part 882 (1029–0057), and on the form OSM–76 for 30 CFR 886.23(b) (1029–0087).

As required under 5 CFR 1320.8(d), a **Federal Register** notice soliciting comments on these collections of information was published on November 9, 2006 (71 FR 65834). No comments were received. This notice provides the public with an additional 30 days in which to comment on the following information collection activity:

Title: Reclamation on Private Lands, 30 CFR 882.

OMB Control Number: 1029–0057.

Summary: Public Law 95–87 authorizes Federal, State, and Tribal governments to reclaim private lands and allows for the establishment of procedures for the recovery of the cost of reclamation activities on privately owned lands. These procedures are intended to ensure that governments have sufficient capability to file liens so that certain landowners will not receive a windfall from reclamation.

Bureau Form Number: None.

Frequency of Collection: Once.

Description of Respondents: State governments and Indian tribes.

Total Annual Responses: 1.

Total Annual Burden Hours: 120.

Title: 30 CFR 886.23(b) and the Abandoned Mine Land Problem Area Description Form, OSM–76.

OMB Control Number: 1029–0087.

Summary: The regulation at 886.23(b) and its implementing form OSM–76 will be used to update the office of Surface Mining Reclamation and Enforcement's inventory of abandoned mine lands. From this inventory, the most serious problem areas are selected for reclamation through the apportionment of funds to States and Indian tribes.

Bureau Form Number: OSM–76.

Frequency of Collection: On occasion.

Description of Respondents: State governments and Indian tribes.

Total Annual Responses: 1,800.

Total Annual Burden Hours: 4,000.

Send comments on the need for the collection of information for the performance of the functions of the agency; the accuracy of the agency's burden estimates; ways to enhance the quality, utility and clarity of the information collection; and ways to minimize the information collection burden on respondents, such as use of automated means of collection of the information, to the following addresses. Please refer to the appropriate OMB control number in all correspondence.

Dated: January 9, 2007.

John R. Craynon,

Chief, Division of Regulatory Support.

[FR Doc. 07–1212 Filed 3–14–07; 8:45 am]

BILLING CODE 4310–05–M

DEPARTMENT OF THE INTERIOR

Office of Surface Mining Reclamation and Enforcement

Notice of Proposed Information for 1029–0047 and 1029–0080

AGENCY: Office of Surface Mining Reclamation and Enforcement.

ACTION: Notice and request for comments.

SUMMARY: In compliance with the Paperwork Reduction Act of 1995, the Office of Surface Mining Reclamation and Enforcement (OSM) is announcing that the information collection requests for the following titles have been forward to the Office of Management and Budget (OMB) for review and approval. These collections are for: 30 CFR parts 816 and 817 relating to the permanent program performance standards—surface mining activities and underground mining activities, and 30 CFR part 850 authorizing State regulatory authorities to develop blaster certification programs. These information collection activities were previously approved by the Office of Management and Budget (OMB), and assigned clearance numbers 1029–0047 and 1029–0080, respectively.

DATES: Comments must be submitted on or before April 16, 2007, to be assured of consideration.

ADDRESSES: Submit comments to the Office of Information and Regulatory Affairs, Office of Management and Budget, Attention: Department of Interior Desk officer, by telefax at (202) 395–6566 or via e-mail to *OIRA_Docket@omb.eop.gov.* Also, please send a copy of your comments to John A. Trelease, Office of Surface Mining Reclamation and Enforcement, 1951 Constitution Ave., NW., Room 202—SIB, Washington, DC 20240, or electronically to *jtrelease@osmre.gov.*

FOR FURTHER INFORMATION CONTACT: To request a copy of either information collection request contact John A. Trelease at (202) 208–2783. You may also contact Mr. Trelease at *jtrelease@osmre.gov.*

SUPPLEMENTARY INFORMATION: The Office of Management and Budget (OMB) regulations at 5 CFR 1320, which implement provisions of the Paperwork Reduction Act of 1995 (Pub. L. 104–13), require that interested members of the public and affected agencies have an opportunity to comment on information collection and recordkeeping activities [see 5 CFR 1320.8(d)]. OSM has submitted two requests to OMB to renew its approval for the collections of information. These are found in 30 CFR parts 816 and 817—Permanent Program Performance Standards—Surface and Underground Mining Activities, and 30 CFR part 850, Permanent Regulatory Program Requirements—Standards for Certification of Blasters. OSM is requesting a 3-year term of approval for these information collection activities.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control number for these collections of information are 1029–0047 for parts 816 and 817, and 1029–0080 for part 850.

As required under 5 CFR 1320.8(d), a **Federal Register** notice soliciting comments on these collections of information was published on October

30, 2006 (71 FR 63353). No comments were received. This notice provides the public with an additional 30 days in which to comment on the following information collection activities:

Title: Permanent Program Performance Standards—Surface and Underground Mining Activities, 30 CFR parts 816 and 817.

OMB Control Number: 1029–0047.

Summary: Section 515 an 516 of the Surface Mining Control and Reclamation Act of 1977 provides that permittees conducting coal mining operations shall meet all applicable performance standards of the act. The information collected is used by the regulatory authority in monitoring and inspecting surface coal mining activities to ensure that they are conducted in compliance with the requirements of the Act.

Bureau Form Number: None.

Frequency of Collection: Once, on occasion, quarterly and annually.

Description of Respondents: Coal mining operators and State regulatory authorities.

Total Annual Response 364,325.

Total Annual Burden Hours: 1,502,105.

Total Annual Non-Wage Burden Cost: $365,246.

Title: Permanent Regulatory Program Requirements—Standards for Certification of Blasters, 30 CFR part 850.

OMB Control Number: 1029–0080.

Summary: This part establishes the requirements and procedures applicable to the development of regulatory programs for the training, examination, and certification of persons engaging in or directly responsible for the use of explosives in surface coal mining operations.

Bureau Form Number: None.

Frequency of Collection: Once.

Description of Respondents: State regulatory authorities.

Total Annual Responses: 1.

Total Annual Burden Hours: 173.

Send comments on the need for the collection of information for the performance of the functions of the agency; the accuracy of the agency's burden estimates; ways to enhance the quality, utility and clarity of the information collection; and ways to minimize the information collection burden on respondents, such as use of automated means of collection of the information, to the following address. Please refer to the appropriate OMB control number in all correspondence.

Dated: January 9, 2007.

John R. Craynon,

Chief Division of Regulatory Support.

[FR Doc. 07–1213 Filed 3–14–07; 8:45 am]

BILLING CODE 4310–05–M

DEPARTMENT OF JUSTICE

Notice of Lodging of Consent Decree Pursuant to Clean Air Act

Notice is hereby given that on February 27, 2007, a proposed consent decree in *United States* v. *E.I. DuPont de Nemours & Co., Inc.,* Civil Action No. 07–930 (JBS), was lodged with the United States District Court for the District of New Jersey.

The proposed consent decree will settle the United States' claims for violation of the Clean Air Act, 42 U.S.C. 7412 and 7413, at the DuPont Environmental Treatment, Chambers Works (''DET''), located in Deepwater, New Jersey. Pursuant to the proposed consent decree, E.I. DuPont de Nemours & Co., Inc., will pay $322,000 as civil penalty for such violations and prepare and submit reports with respect to future activities at the DET.

The Department of Justice will receive for a period of thirty (30) days from the date of this publication comments relating to the proposed consent decree. Comments should be addressed to the Assistant Attorney General of the Environment and Natural Resources Division, and either e-mailed to *pubcomment-ees.enrd@usdoj.gov* or mailed to P.O. Box 7611, U.S. Department of Justice, Washington, DC 20044–7611, and should refer to *United States* v. *E.I. DuPont de Nemours & Co., Inc.,* Civil Action No. 07–930 (JBS), D.J. Ref. 90–5–2–1–08003.

The proposed consent decree may also be examined at the Office of the United States Attorney, District of New Jersey, 970 Broad Street, Suite 700, Newark, New Jersey, and at U.S. EPA Region 2, 290 Broadway, New York, New York. During the public comment period, the proposed consent decree may also be examined on the following Department of Justice Web site, *http://www.usdoj.gov/enrd/Consent_Decrees.html.*

A copy of the proposed consent decree may also be obtained by mail from the Consent Decree Library, P.O. Box 7611, U.S. Department of Justice, Washington, DC 20044–7611 or by faxing or e-mailing a request to Tonia Fleetwood (*tonia.fleetwood@usdoj.gov*), fax no. (202) 514–0097, phone confirmation number (202) 514–1547. If requesting a copy of the proposed consent decree (without attachments), please so note and enclose a check in the amount of $4.75 (25 cent per page reproduction cost) payable to the U.S. Treasury or if by e-mail or fax, forward a check in that amount to the Consent Decree Library at the stated address.

Ronald Gluck,

Assistant Chief, Environmental Enforcement Section, Environment and Natural Resources Division.

[FR Doc. 07–1203 Filed 3–14–07; 8:45 am]

BILLING CODE 4410–15–M

DEPARTMENT OF JUSTICE

[AAG/A Order No. 007–2007]

Privacy Act of 1974; Removal of a System of Records Notice

Pursuant to the provisions of the Privacy Act of 1974 (5 U.S.C. 552a), the Department of Justice (DOJ) is removing a published notice of a Privacy Act system of records: the Deputy Attorney General's (DAG) ''Miscellaneous Attorney Personnel Records System, JUSTICE/DAG–011,'' last published in the **Federal Register** on October 21, 1985 at 50 FR 42613.

The information contained within this system of records is now covered by two applicable notices of systems of records of the Office of Personnel Management (OPM): ''General Personnel Records, OPM/GOVT–1,'' last published in the **Federal Register** on June 19, 2006 at 71 FR 35342; and ''Records of Adverse Actions, Performance Based Reduction in Grade and Removal Actions, and Termination of Probationers, OPM/GOVT–3,'' last published in the **Federal Register** on June 19, 2006 at 71 FR 35342, 35350. The DAG ''Miscellaneous Attorney Personnel Records System'' records are also covered by a Department-wide system notice, ''Personnel Investigation and Security Clearance Records for the Department of Justice, DOJ–006,'' last published in full text in the **Federal Register** on September 24, 2002 at 67 FR 59864, and amended in part on November 10, 2004 at 69 FR 65224.

Therefore, the notice of ''Miscellaneous Attorney Personnel Records System, JUSTICE/DAG–011'' is removed from the Department's listing of Privacy Act systems of records notices, effective on the date of publication of this notice.

Dated: March 6, 2007.

Lee J. Lofthus,

Assistant Attorney General for Administration.

[FR Doc. E7–4776 Filed 3–14–07; 8:45 am]

BILLING CODE 4410–PB–P

DEPARTMENT OF JUSTICE

[AAG/A Order No. 006–2007]

Privacy Act of 1974; Removal of a System of Records Notice

Pursuant to the provisions of the Privacy Act of 1974 (5 U.S.C. 552a), the Department of Justice (DOJ) is removing the published notice of a Privacy Act system of records: the Deputy Attorney General's (DAG) ''Summer Intern Program Records System, JUSTICE/DAG–009,'' last published in the **Federal Register** on October 21, 1985 at 50 FR 42611.

This system notice is unnecessary because the records are adequately covered both by: the Government-wide system of records notice published by the Office of Personnel Management (OPM), ''OPM/GOVT–5, Recruiting, Examining, and Placement Records,'' last published in the **Federal Register** on June 19, 2006 at 71 FR 35342, 35351; and the Department of Justice system of records, ''DOJ–006, Personnel Investigation and Security Clearance Records for the Department of Justice, '' last published in the **Federal Register** in full text on September 24, 2002 at 67 FR 59864, and amended in part on November 10, 2004 at 69 FR 65224.

Therefore, the notice of ''Summer Intern Program Records System, JUSTICE/DAG–009,'' is removed from the Department's listing of Privacy Act systems of records notices, effective on the date of publication of this notice in the **Federal Register**.

Dated: March 6, 2007.

Lee J. Lofthus,

Assistant Attorney General for Administration.

[FR Doc. E7–4779 Filed 3–14–07; 8:45 am]

BILLING CODE 4410–PB–P

DEPARTMENT OF JUSTICE

[AAG/A Order No. 004–2007]

Privacy Act of 1974; System of Records

AGENCY: Department of Justice.

ACTION: Notice.

SUMMARY: Pursuant to the Privacy Act of 1974 (5 U.S.C. 552a) and Office of Management and Budget (OMB) Circular No. A–130, Appendix I, Federal Agency Responsibilities for Maintaining Records About Individuals, notice is hereby given that the Department of Justice (DOJ or Justice) is establishing the following new system of records: ''Justice Federal Docket Management System [Justice FDMS], DOJ–013.'' Justice FDMS allows the public to search, view, download, and comment on all Department of Justice rulemaking documents in one central online system. This system notice covers the various records maintained by all Department of Justice components pertaining to public comments under the Justice FDMS.

DATES: In accordance with 5 U.S.C. 552a (e)(4) and (11), the public is given a 30-day period in which to comment, and the Office of Management and Budget (OMB) which has oversight responsibility under the Privacy Act, requires a 40-day period in which to conclude its review of the system. Written comments must be postmarked, and electronic comments must be sent, on or before April 24, 2007.

ADDRESSES: Address all comments to Mary Cahill, Management Analyst, Management and Planning Staff, Justice Management Division, Department of Justice, Washington, DC 20530, *mary.e.cahill@usdoj.gov*, facsimile number 202–307–1853.

FOR FURTHER INFORMATION CONTACT: Mike Duffy, Deputy Chief Information Officer for E-Government on 202–514–0507.

SUPPLEMENTARY INFORMATION: The Federal Docket Management System (FDMS) serves as a central, electronic repository for all Federal rulemaking dockets, which may include, but are not necessarily limited to, **Federal Register** Notices of Proposed Rulemaking, Interim Rules, supporting materials such as scientific or economic analyses, and public comments, as well as non-rulemaking dockets, such as Notices, at the option of the agency or component. Although it is likely that, in the future, the Department will use the FDMS as its electronic record keeping system in accordance with the Federal Records Act, 44 U.S.C. 3301 *et seq.*, for DOJ FDMS records, at present the permanent recordkeeping system for DOJ will remain a paper record keeping system. The FDMS is a system used by all Federal agencies that conduct rulemakings.

The Department of Justice is publishing this new system of records notice for the E-Government, E-Rulemaking Initiative's FDMS, in order to satisfy the applicable requirements of the Privacy Act. Previously the Environmental Protection Agency (EPA) published a notice in the **Federal Register** (70 FR 15086, March 24, 2005) as the Program Manager for the Federal-wide E-Rulemaking Initiative. This present notice provides information specific to the Department of Justice and its components and their use of electronic documents posted on, or submitted to, Justice FDMS, and replaces the EPA notice for DOJ records in the FDMS.

Members of the public who use FDMS to submit a comment on a DOJ Federal rulemaking may be asked to provide name and contact information (e-mail or mailing address). If that comment meets all requirements, as determined by the Department of Justice or the component publishing the rulemaking, the comment will be posted on the Internet at the FDMS Web site—*http://www.regulations.gov*—for public viewing, and all the contents of the posted comment will be searchable. The FDMS is a system with full text search capability, that would include any name and identifying information submitted in the body of the comment. Names of individuals and organizations submitting comments using Justice FDMS will be posted on the *http://www.regulations.gov* site with their respective comments for public viewing. Contact information (e-mail or mailing address) will not be available for public viewing, unless the submitter includes that information in the body of the comment. Under any circumstances, contact information will be retained by the agency or the component as part of this system.

A component may choose not to post certain types of information contained in a comment submission, yet preserve the entire comment to be reviewed and considered as part of the rulemaking docket by the component. For example, comments containing material restricted from disclosure by Federal statute may not be publicly posted, but will be retained and evaluated/considered by the receiving component.

The Justice FDMS contains information that is submitted to the Department in support of Federal rulemakings. The portion of this system that is covered by the Privacy Act includes the personally identifiable information submitted by commenters.

In accordance with 5 U.S.C. 552a (r), the Department has provided a report to OMB and appropriate Members of Congress.

Dated: March 5, 2007.

Lee J. Lofthus,

Assistant Attorney General for Administration.

Department of Justice

DOJ–013

SYSTEM NAME:

Justice Federal Docket Management System (Justice FDMS).

SECURITY CLASSIFICATION:

None.

SYSTEM LOCATION:

U.S. Department of Justice, 950 Pennsylvania Ave., NW., Washington, DC 20530 and other Department of Justice offices.

CATEGORIES OF INDIVIDUALS COVERED BY THE SYSTEM:

Any person—including private individuals, representatives of Federal, State or local governments, businesses, and industries, that provides personally identifiable information pertaining to DOJ and persons mentioned or identified in the body of a comment.

CATEGORIES OF RECORDS IN THE SYSTEM:

Agency rulemaking material includes but is not limited to public comments received through FDMS pertaining to DOJ rulemaking where such comments contain personally identifiable information; and any other supporting rulemaking documentation.

AUTHORITY FOR MAINTENANCE OF THE SYSTEM:

Section 206(d) of the E-Government Act of 2002 (Pub. L. 107–347, 44 U.S.C. Chapter 36).

PURPOSE(S):

To assist the Federal Government in allowing the public to search, view, download, and comment on Federal agency rulemaking documents in one central on-line location and to contact commenters if necessary.

ROUTINE USES OF RECORDS MAINTAINED IN THE SYSTEM INCLUDING CATEGORIES OF USERS AND THE PURPOSES OF SUCH USES:

A. Where a record, either alone or in conjunction with other information, indicates a violation or potential violation of law—criminal, civil, or regulatory in nature—the relevant records may be referred to the appropriate Federal, State, local, tribal, or foreign law enforcement authority or other appropriate entity charged with the responsibility for investigating or prosecuting such violation or charged with enforcing or implementing such law.

B. To appropriate officials and employees of a Federal agency or entity that requires information relevant to a decision concerning the hiring, appointment, or retention of an employee; the issuance, renewal, suspension, or revocation of a security clearance; the execution of a security or suitability investigation; the letting of a contract; or the issuance of a grant or benefit.

C. To Federal, State, local, tribal, foreign, or international licensing agencies or associations which require information concerning the suitability or eligibility of an individual for a license or permit.

D. Information may be disclosed to the Office of Management and Budget at any stage in the legislative coordination and clearance process in connection with private relief legislation as set forth in OMB Circular No. A–19, Circular No. A–130, Appendix I, Federal Agency Responsibilities for Maintaining Records About Individuals.

E. To a Member of Congress or staff acting upon the Member's behalf when the Member or staff requests the information on behalf of, and at the request of, the individual who is the subject of the records.

F. In an appropriate proceeding before a court, or administrative or adjudicative body, when the Department of Justice determines that the records are arguably relevant to the proceeding; or in an appropriate proceeding before an administrative or adjudicative body when the adjudicator determines the records to be relevant to the proceeding.

G. To the National Archives and Records Administration (NARA) for purposes of records management inspections conducted under the authority of 44 U.S.C. 2904 and 2906.

H. To contractors, grantees, experts, consultants, students, and others performing or working on a contract, service, grant, cooperative agreement, or other assignment for the Federal Government, when necessary to accomplish an agency function related to this system of records.

I. To an actual or potential party to litigation or the party's authorized representative for the purpose of negotiation or discussion of such matters as settlement, plea bargaining, or in informal discovery proceedings.

J. To the news media and the public, including disclosures pursuant to 28 CFR 50.2, unless it is determined that release of the specific information in the context of a particular case would constitute an unwarranted invasion of personal privacy.

K. To a former employee of the Department for purposes of: responding to an official inquiry by a Federal, State, or local government entity or professional licensing authority, in accordance with applicable Department regulations; or facilitating communications with a former employee that may be necessary for personnel-related or other official purposes where the Department requires information and/or consultation assistance from the former employee regarding a matter within that person's former area of responsibility.

L. To such recipients and under such circumstances and procedures as are mandated by Federal statute or treaty.

M. To the White House (the President, Vice-President, their staffs, and other entities of the Executive Office of the President), and, during Presidential transitions, to the President Elect and Vice-President Elect and their designated transition team staff, for coordination of activities that relate to or have an effect upon the carrying out of the constitutional, statutory, or other official or ceremonial duties of the President, President Elect, Vice-President or Vice-President Elect.

N. To appropriate agencies, entities, and persons when (1) the Department suspects or has confirmed that the security or confidentiality of information in the system of records has been compromised; (2) the Department has determined that as a result of the suspected or confirmed compromise there is a risk of harm to economic or property interests, identity theft or fraud, or harm to the security or integrity of this system or other systems or programs (whether maintained by the Department or another agency or entity) that rely upon the compromised information; and (3) the disclosure made to such agencies, entities, and persons is reasonably necessary to assist in connection with the Department's efforts to respond to the suspected or confirmed compromise and prevent, minimize, or remedy such harm.

DISCLOSURE TO CONSUMER REPORTING AGENCIES:

Not Applicable.

POLICIES AND PRACTICES FOR STORING, RETRIEVING, ACCESSING, RETAINING, AND DISPOSING OF RECORDS IN THE SYSTEM:

STORAGE:

Records will be maintained in computer databases compliant with DOD 5015.2 electronic records standards. A paper copy of all rulemaking docket materials will also be maintained by the components and constitutes the official record.

RETRIEVABILITY:

The FDMS will have the ability to retrieve records by various data elements and key word searches, including: Name, Agency, Component, Docket Type, Docket Sub-Type, Agency Docket ID, Docket Title, Docket Category, Document Type, CFR Part, Date Comment Received, and **Federal Register** Published Date.

SAFEGUARDS:

Justice FDMS security protocols will meet multiple NIST Security Standards

from Authentication to Certification and Accreditation. Records in the Justice FDMS will be maintained in a secure, password protected electronic system that will utilize security hardware and software to include: multiple firewalls, active intruder detection, and role-based access controls. Additional safeguards will vary by component.

RETENTION AND DISPOSAL:

Each component will handle its records in accordance with its records schedule as approved by the National Archives and Records Administration (NARA). Electronic data will be retained and disposed of in accordance with the component's records schedule pending approval by the NARA. The majority of documents residing on this system will be public comments and other documentation in support of Federal rulemakings. All **Federal Register** rulemakings are part of the Justice FDMS and are identified as official records and retained by NARA.

SYSTEM MANAGERS AND ADDRESSES:

Technical Issues: Justice Department, Deputy Chief Information Officer for E-Government, Office of the Chief Information Officer, United States Department of Justice, 950 Pennsylvania Avenue, NW., RFK Main Building, Washington, DC 20530.

Policy Issues: Justice Department FDMS Policies System Administrator, Office of Legal Policy, United States Department of Justice, 950 Pennsylvania Avenue, NW., RFK Main Building, Washington, DC 20530.

Component Managers can be contacted through the Department's System Managers.

NOTIFICATION PROCEDURE:

Records concerning comments received through FDMS pertaining to DOJ rulemaking are maintained by the individual DOJ component to which the comment was directed. Inquiries regarding these records should be addressed to the particular DOJ component maintaining the records at Department of Justice, 950 Pennsylvania Avenue, NW., RFK Main Building, Washington, DC 20530. For records concerning the DOJ FDMS system generally, requests should be made to the System Manager for technical or policy issues as appropriate, listed above.

RECORD ACCESS PROCEDURES:

Requests for access may be made by appearing in person or by writing to the appropriate system manager at the address indicated in the System Managers and Addresses section, or as described in the Notification Procedures, above. The envelope and letter should be clearly marked ''Privacy Act Request.'' The request should include a general description of the records sought and must include the requester's full name, current address, and date and place of birth. The request must be signed, dated, and either notarized or submitted under penalty of perjury. Although no specific form is required, forms may be obtained for this purpose from the FOIA/PA Mail Referral Unit, Justice Management Division, United States Department of Justice, 950 Pennsylvania Avenue, NW., Washington DC 20530–0001, or on the Department of Justice Web site at *http://www.usdoj.gov/04foia/att_d.htm*.

CONTESTING RECORDS PROCEDURES:

Individuals seeking to contest or amend information maintained in the system should direct their requests to the appropriate system manager at the address indicated in the System Managers and Addresses section, or as described in the Notification Procedures, above, stating clearly and concisely what information is being contested, the reasons for contesting it, and the proposed amendment to the information sought.

RECORD SOURCE CATEGORIES:

Any person, including public citizens and representatives of Federal, state or local governments; businesses; and industries.

EXEMPTIONS CLAIMED FOR THE SYSTEM:

None.

[FR Doc. E7–4782 Filed 3–14–07; 8:45 am]
BILLING CODE 4410–FB–P

DEPARTMENT OF JUSTICE

Antitrust Division

Notice Pursuant to the National Cooperative Research and Production Act of 1993—Mobile Enterprise Alliance, Inc.

Notice is hereby given that, on February 1, 2007, pursuant to Section 6(a) of the National Cooperative Research and Production Act of 1993, 15 U.S.C. 4301 *et seq.* (''the Act''), Mobile Enterprise Alliance, Inc. has filed written notifications simultaneously with the Attorney General and the Federal Trade Commission disclosing changes in its membership. The notifications were filed for the purpose of extending the Act's provisions limiting the recovery of antitrust plaintiffs to actual damages under specified circumstances. Specifically, Traverse Networks, Newark, CA has withdrawn as a party to this venture.

No other changes have been made in either the membership or planned activity of the group research project. Membership in this group research project remains open, and Mobile Enterprise Alliance, Inc. intends to file additional written notifications disclosing all changes in membership.

On June 24, 2004, Mobile Enterprise Alliance, Inc. filed its original notification pursuant to Section 6(a) of the Act. The Department of Justice published a notice in the **Federal Register** pursuant to Section 6(b) of the Act on July 23, 2004 (69 FR 44062).

The last notification was filed with the Department on October 27, 2006. A notice was published in the **Federal Register** pursuant to Section 6(b) of the Act on November 22, 2006 (71 FR 67642).

Patricia A. Brink,

Deputy Director of Operations, Antitrust Division.

[FR Doc. 07–1197 Filed 3–14–07; 8:45 am]
BILLING CODE 4410–11–M

DEPARTMENT OF JUSTICE

Antitrust Division

Notice Pursuant to the National Cooperative Research and Production Act of 1993—National Center for Manufacturing Sciences, Inc.

Notice is hereby given that, on February 15, 2007, pursuant to Section 6(a) of the National Cooperative Research and Production Act of 1993, 15 U.S.C. 4301 *et seq.* (''the Act''), National Center for Manufacturing Sciences, Inc. (''NCMS'') has filed written notifications simultaneously with the Attorney General and the Federal Trade Commission disclosing changes in its membership. The notifications were filed for the purpose of extending the Act's provisions limiting the recovery of antitrust plaintiffs to actual damages under specified circumstances. Specifically, America's Phenix, Inc., Washington, DC; American Foundry Society, Inc., Schaumburg, IL; DuPoint Fuel Cells Business Unit, E.I. du Pont de Nemours & Company, Wilmington, DE; Goodrich, Fuel & Utility Systems, Simmonds Precision Products Inc., Vergennes, VT; Imaginestics, LLC, West Lafayette, IN; Net-Inspect LLC, Bellevue, WA; Profile Composites Inc., Sidney, British Columbia, CANADA; REI Systems, Inc., Vienna, VA; Renaissance Services Inc., Springfield, OH; SCRA, Charleston, SC;

SFC Smart Fuel Cell AG, Brunnthal-Nord, GERMANY; and VCAMM, Bemont, VIC, AUSTRALIA have been added as parties to this venture. Also, Advance Assembly Automation Division, Dayton, OH; Automatic Feed Co., Napoleon, OH; Bardons & Oliver, Inc., Solon, OH; Bertsche Engineering Corp., Buffalo Grove, IL; CGTech, Irvine, CA; Control Gaging Inc., Ann Arbor, MI; Detroit Tool and Engineering, Inc., Vernon Hills, IL; Drake Manufacturing Services, Inc., Warren, OH; Gehring L.P., Farmington Hills, MI; Global Shop Solutions, The Woodlands, TX; Nuvonyx, Inc., Bridgeton, MO; PIA Group, Inc., Cincinnati, OH; Positrol, Inc., Cincinnati, OH; Preco Industries, Inc., Lenexa, KS; Prima North America, Inc., Champlin, MN; Remmele Engineering, Inc., Big Lake, MN; Rimrock Automation, New Berlin, WI; Sunnen Products Company, St. Louis, MO; The Gleason Works, Rochester, NY; and Unist, Inc., Grand Rapids, MI have withdrawn as parties to this venture.

No other changes have been made in either the membership or planned activity of the group research project. Membership in this group research project remains open, and NCMS intends to file additional written notification disclosing all changes in membership.

On February 20, 1987, NCMS filed its original notification pursuant to Section 6(a) of the Act. The Department of Justice published a notice in the **Federal Register** pursuant to Section 6(b) of the Act on March 17, 1987 (52 FR 8375).

The last notification was filed with the Department of Justice on July 26, 2006. A notice was published in the **Federal Register** pursuant to Section 6(b) of the Act on August 16, 2006 (71 FR 47248).

Patricia A. Brink,

Deputy Director of Operations, Antitrust Division.

[FR Doc. 07–1198 Filed 3–14–07; 8:45 am]

BILLING CODE 4410–11–M

DEPARTMENT OF JUSTICE

Antitrust Division

Notice Pursuant to the National Cooperative Research and Production Act of 1993—Open DeviceNet Vendor Association, Inc.

Notice is hereby given that, on January 29, 2007, pursuant to Section 6(a) of the National Cooperative Research and Production Act of 1993, 15 U.S.C. 4301 *et seq.* (''the Act''), Open DeviceNet Vendor Association, Inc. (''ODVA'') has filed written notifications simultaneously with the Attorney General and the Federal Trade Commission disclosing changes in its membership. The notifications were filed for the purpose of extending the Act's provisions limiting the recovery of antitrust plaintiffs to actual damages under specified circumstances. Specifically, Mettler-Toledo, Inc., Columbus, OH; Ground Fault Systems bv, Enschede, THE NETHERLANDS; Shanghai Sibotech Automation Co., Ltd., Shanghai, PEOPLE'S REPUBLIC OF CHINA; UNIPULSE Corporation, Koshigaya City, Saitama, JAPAN; Software Horizons Inc., North Billerica, MA; Souriau USA, Inc., York, PA; Kashiyama Industries, Ltd., Nagano, JAPAN; Spectrum Controls, Inc., Issaquah, WA; AC&T Systems, Kyunggi-do, REPUBLIC OF KOREA; Korenix Technology Co., Ltd., Taipei, TAIWAN; Chun IL Electric Ind. Co., Busan, REPUBLIC OF KOREA; Shinho System, Seoul, REPUBLIC OF KOREA; INNOBIS, Cheonan-si, Chungcheongnam-do, REPUBLIC OF KOREA; Northern Network Solutions LLC, Auburn Hills, MI; Ten X Technology, Inc., Austin, TX; KVC Co. Ltd., Gyeonggi-do, REPUBLIC OF KOREA; Symbol Technologies, Inc., Holtsville, NY; Advantech Automation Corporation, Cincinatti, OH; BTR NETCOM, a division of RIA Connect, Inc., Tinton Falls, NJ; and Bernecker+Rainer Industrie Electronik Ges. m.b.H, Eggelsberg, AUSTRIA have been added as parties to this venture.

Also, Radic Technology, Milpitas, CA; Leybold Vakuum GmbH, Cologne, GERMANY; Sharp Manufacturing Systems Corporation, Osaka, JAPAN; Brooks Automation, Chelmsford, MA; HM Computing, Malvern, Worcestershire, UNITED KINGDOM; ISAS (Integrated Switchgear & Systems P/L), Darwin, N.T., AUSTRALIA; Keyence Corporation, Osaka, JAPAN; and Mykrolis Corporation (Millipore) (Entegris), Allen, TX have withdrawn as parties to this venture.

In addition, Belden CDT has changed its name to Belden, Richmond, IN; Enercorn-Nord Electronic GmbH has changed its name to Nord Electronic DRIVESYSTEMS GmbH, Hamburg, GERMANY; Rockwell Samsung Automation has changed its name to Rockwell Automation Korea, Suwon Kyunggi-do, REPUBLIC OF KOREA; CELERITY (Kinetics/Unit Instruments) has changed its name to Celerity, Inc., Yorba Linda, CA.

No other changes have been made in either the membership or planned activity of the group research project. Membership in this group research project remains open, ODVA intends to file additional written notifications disclosing all changes in membership.

On June 21, 1995, ODVA filed its original notification pursuant to Section 6(a) of the Act. The Department of Justice published a notice in the **Federal Register** pursuant to Section 6(b) of the Act on February 15, 1996 (61 FR 6039).

The last notification was filed with the Department on May 31, 2006. A notice was published in the **Federal Register** pursuant to Section 6(b) of the Act on June 15, 2006 (71 FR 34645).

Patricia A. Brink,

Deputy Director of Operations, Antitrust Division.

[FR Doc. 07–1199 Filed 3–14–07; 8:45 am]

BILLING CODE 4410–11–M

DEPARTMENT OF JUSTICE

Antitrust Division

Notice Pursuant to the National Cooperative Research and Production Act of 1993—Semiconductor Test Consortium, Inc.

Notice is hereby given that, on January 17, 2007, pursuant to Section 6(a) of the National Cooperative Research and Production Act of 1993, 15 U.S.C. 4301 *et seq.* (''the Act''), Semiconductor Test Consortium, Inc. has filed written notifications simultaneously with the Attorney General and the Federal Trade Commission disclosing changes in its membership. The notifications were filed for the purpose of extending the Act's provisions limiting the recovery of antitrust plaintiffs to actual damages under specified circumstances. Specifically, Rasco GmbH, Kolbermoor, GERMANY; Gerhard Kessler, Munich, GERMANY; Rood Technology GmbH & Co., Nordlingen, GERMANY; Multitestelektron Systems GmbH, Rosenheim, GERMANY; and Form Factor, Inc., Livermore, CA have been added as parties to this venture.

Also, Xandex, Inc., Petaluma, CA; Swanson Semiconductor Service, Fort Worth, TX; PXIT, Lexington, MA; HILEVEL, Irvine, CA; and EADS-North American Defense, Irvine, CA have withdrawn as parties to this venture. In addition, Philips Semiconductors has changed its name to NXP Semiconductors, San Jose, CA.

No other changes have been made in either the membership or planned activity of the group research project. Membership in this group research project remains open, and Semiconductor Test Consortium, Inc. intends to file additional written

notifications disclosing all changes in membership.

On May 27, 2003, Semiconductor Test Consortium, Inc. filed its original notification pursuant to Section 6(a) of the Act. The Department of Justice published a notice in the **Federal Register** pursuant to Section 6(b) of the Act on June 17, 2003 (68 FR 35913).

The last notification was filed with the Department on October 25, 2006. A notice was published in the **Federal Register** pursuant to Section 6(b) of the Act on November 22, 2006 (71 FR 67643).

Patricia A. Brink,

Deputy Director of Operations, Antitrust Division.

[FR Doc. 07–1200 Filed 3–14–07; 8:45 am]

BILLING CODE 4410–11–M

DEPARTMENT OF LABOR

Mine Safety and Health Administration

Proposed Information Collection Request Submitted for Public Comment and Recommendations; Safety Standards for Underground Coal Mine Ventilation—Belt Entry Used as an Intake Air Course To Ventilate Working Sections and Areas Where Mechanized Mining Equipment Is Being Installed or Removed

ACTION: Notice.

SUMMARY: The Department of Labor, as part of its continuing effort to reduce paperwork and respondent burden conducts a pre-clearance consultation program to provide the general public and Federal agencies with an opportunity to comment on proposed and/or continuing collections of information in accordance with the Paperwork Reduction Act of 1995 (PRA95) [44 U.S.C. 3506 (c)(2)(A)]. This program helps to ensure that requested data can be provided in the desired format, reporting burden (time and financial resources) is minimized, collection instruments are clearly understood, and the impact of collection requirements on respondents can be properly assessed.

Currently, the Mine Safety and Health Administration (MSHA) is soliciting comments concerning the extension of the information collection related to 30 CFR Sections 75.350, 75.351, 75.352 and 75.371.

DATES: Submit comments on or before May 14, 2007.

ADDRESSES: Send comments to, Debbie Ferraro, Management Services Division, 1100 Wilson Boulevard, Room 2171, Arlington, VA 22209–3939. Commenters are encouraged to send their comments on computer disk, or via Internet E-mail to *Ferraro.Debbie@DOL.GOV*. Ms. Ferraro can be reached at (202) 693–9821 (voice), or (202) 693–9801 (facsimile).

FOR FURTHER INFORMATION CONTACT: The employee listed in the **ADDRESSES** section of this notice.

SUPPLEMENTARY INFORMATION:

I. Background

The Safety Standards for Underground Coal Mine Ventilation—Belt Entry rule provides safety requirements for the use of the conveyor belt entry as a ventilation intake to course fresh air to working sections and areas where mechanized mining equipment is being installed or removed in mines with three or more entries. This rule is a voluntary standard. If the mine operators choose to use belt air to ventilate working places, the provisions will maintain the level of safety in underground mines while allowing them to implement advances in mining atmospheric monitoring technology. This rule offers alternate provisions that mine operators need to follow if they want to use belt air to ventilate working sections.

II. Desired Focus of Comments

MSHA is particularly interested in comments that:

- Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;
- Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used
- Enhance the quality, utility, and clarity of the information to be collected; and
- Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g., permitting electronic submissions of responses.

A copy of the proposed information collection request can be obtained by contacting the employee listed in the **FOR FURTHER INFORMATION CONTACT** section of this notice, or viewed on the Internet by accessing the MSHA home page (*http://www.msha.gov*) and then choosing ''Statutory and Regulatory Information'' and ''**Federal Register** Documents.''

III. Current Actions

This request for collection of information from mine operators that elect to use belt air to ventilate working sections and areas where mechanized equipment is being installed or removed will be used by coal mine supervisors and employees, State mine inspectors, and Federal mine inspectors. The information will provide insight into the hazardous conditions that have been encountered and those that may be encountered. The records of inspections greatly assist those who use them in making decisions that will ultimately affect the safety and health of miners working in belt air mines.

Type of Review: Extension.

Agency: Mine Safety and Health Administration.

Title: Safety Standards for Underground Coal Mine Ventilation—Belt Entry Used as an Intake Air Course to Ventilate Working Sections and Areas Where Mechanized Mining Equipment Is Being Installed or Removed.

OMB Number: 1219–0138.

Frequency: On Occasion.

Affected Public: Business or other for-profit.

Respondents: 45.

Total Burden Hours: 9758.

Total Burden Cost (operating/maintaining): $87,137.

Comments submitted in response to this notice will be summarized and/or included in the request for Office of Management and Budget approval of the information collection request; they will also become a matter of public record.

Dated at Arlington, Virginia, this 9th day of March, 2007.

David L. Meyer,

Director, Office of Administration and Management.

[FR Doc. E7–4723 Filed 3–14–07; 8:45 am]

BILLING CODE 4510–43–P

DEPARTMENT OF LABOR

Occupational Safety and Health Administration

[Docket No. OSHA–2007–0014]

Standard on Additional Requirements for Special Dipping and Coating Operations (Dip Tanks); Extension of the Office of Management and Budget's Approval of Information Collection (Paperwork) Requirement

AGENCY: Occupational Safety and Health Administration (OSHA), Labor.

ACTION: Request for public comment.

SUMMARY: OSHA solicits public comment concerning its proposal to extend OMB approval of the information collection requirement specified in its standard on Additional Requirements for Special Dipping and Coating Operations (Dip Tanks) (29 CFR 1910.126(g)(4)). The provision is to ensure that employers make employees aware of the minimum distance between goods being electrostatically deteared.

DATES: Comments must be submitted (postmarked, sent, or received) by May 14, 2007.

ADDRESSES: *Electronically:* You may submit comments and attachments electronically at *http://www.regulations.gov*, which is the Federal eRulemaking Portal. Follow the instructions online for submitting comments.

Facsimile: If your comments, including attachments, are not longer than 10 pages, you may fax them to the OSHA Docket Office at (202) 693–1648.

Mail, hand delivery, express mail, messenger, or courier service: When using this method, you must submit three copies of your comments and attachments to the OSHA Docket Office, OSHA Docket No. OSHA–2007–0014, U.S. Department of Labor, Occupational Safety and Health Administration, Room N–2625, 200 Constitution Avenue, NW., Washington, DC 20210. Deliveries (hand, express mail, messenger, and courier service) are accepted during the Department of Labor's and Docket Office's normal business hours, 8:15 a.m. to 4:45 p.m., e.t.

Instructions: All submissions must include the Agency name and OSHA docket number for the ICR (OSHA Docket No. OSHA–2007–0014). All comments, including any personal information you provide, are placed in the public docket without change, and may be made available online at *http://www.regulations.gov*. For further information on submitting comments see the ''Public Participation'' heading in the section of this notice titled **SUPPLEMENTARY INFORMATION**.

Docket: To read or download comments or other material in the docket, go to *http://www.regulations.gov* or the OSHA Docket Office at the address above. All documents in the docket (including this **Federal Register** notice) are listed in the *http://www.regulations.gov* index; however, some information (e.g., copyrighted material) is not publicly available to read or download through the Web site. All submissions, including copyrighted material, are available for inspection and copying at the OSHA Docket Office. You may also contact Theda Kenney at the address below to obtain a copy of the ICR.

FOR FURTHER INFORMATION CONTACT: Theda Kenney or Todd Owen, Directorate of Standards and Guidance, OSHA, U.S. Department of Labor, Room N–3609, 200 Constitution Avenue, NW., Washington, DC 20210; telephone (202) 693–2222.

SUPPLEMENTARY INFORMATION:

I. Background

The Department of Labor, as part of its continuing effort to reduce paperwork and respondent (i.e., employer) burden, conducts a preclearance consultation program to provide the public with an opportunity to comment on proposed and continuing information collection requirements in accordance with the Paperwork Reduction Act of 1995 (44 U.S.C. 3506(c)(2)(A)). This program ensures that information is in the desired format, reporting burden (time and costs) is minimal, collection instruments are clearly understood, and OSHA's estimate of the information collection burden is accurate. The Occupational Safety and Health Act of 1970 (the OSH Act) (29 U.S.C. 651 *et seq.*) authorizes information collection by employers as necessary or appropriate for enforcement of the Act or for developing information regarding the causes and prevention of occupational injuries, illnesses, and accidents (29 U.S.C. 657). The OSH Act also requires that OSHA obtain such information with minimum burden upon employers, especially those operating small businesses, and to reduce to the maximum extent feasible unnecessary duplication of efforts in obtaining information (29 U.S.C. 657).

The standard on Additional Requirements for Special Dipping and Coating Operations, 29 CFR 1910.126(g)(4)), requires employers to post a conspicuous sign near each piece of electrostatic detearing equipment that notifies employees of the minimum safe distance they must maintain between goods undergoing electrostatic detearing and the electrodes or conductors of the equipment used in the process. Doing so reduces the likelihood of igniting the explosive chemicals used in electrostatic detearing operations.

II. Special Issues for Comment

OSHA has a particular interest in comments on the following issues:

• Whether the proposed information collection requirement is necessary for the proper performance of the Agency's functions to protect employees, including whether the information is useful;

• The accuracy of OSHA's estimate of the burden (time and costs) of the information collection requirement, including the validity of the methodology and assumptions used;

• The quality, utility, and clarity of the information collected; and

• Ways to minimize the burden on employers who must comply; for example, by using automated or other technological information collection and transmission techniques.

III. Proposed Actions

OSHA is requesting that OMB extend its approval of the information collection requirement contained in the Standard on Additional Requirements for Special Dipping and Coating Operations (Dip Tanks) (29 CFR 1910.126(g)(4)). The Agency is requesting to retain its previous burden hour estimate of 1 hour. The Agency will summarize the comments submitted in response to this notice, and will include this summary in the request to OMB.

Type of Review: Extension of currently approved information collection requirement.

Title: Standard on Additional Requirements for Special Dipping and Coating Operations (Dip Tanks) (29 CFR 1910.126).

OMB Number: 1218–0237.

Affected Public: Business or other for-profit.

Number of Respondents: 0.

Frequency of Recordkeeping: On occasion.

Total Responses: 1.

Average Time Per Response: 0.

Estimated Total Burden Hours: 1.

Estimated Cost (Operation and Maintenance). $0.

IV. Public Participation—Submission of Comments on this Notice and Internet Access to Comments and Submissions

You may submit comments in response to this document as follows: (1) Electronically at *http://www.regulations.gov*, which is the Federal eRulemaking Portal; (2) by facsimile (FAX); or (3) by hard copy. All comments, attachments, and other material must identify the Agency name and the OSHA docket number for the ICR (OSHA Docket No. OSHA–2007–0014). You may supplement electronic submissions by uploading document files electronically. If you wish to mail additional materials in reference to an electronic or facsimile submission, you must submit them to the OSHA Docket Office (see the section of this notice titled **ADDRESSES**). The additional

materials must clearly identify your electronic comments by your name, date, and the docket number so the Agency can attach them to your comments.

Because of security procedures, the use of regular mail may cause a significant delay in the receipt of comments. For information about security procedures concerning the delivery of materials by hand, express delivery, messenger, or courier service, please contact the OSHA Docket Office at (202) 693–2350 (TTY (877) 889–5627).

Comments and submissions are posted without change at *http://www.regulations.gov*. Therefore, OSHA cautions commenters about submitting personal information such as social security numbers and date of birth. Although all submissions are listed in the *http://www.regulations.gov* index, some information (e.g., copyrighted material) is not publicly available to read or download through this website. All submissions, including copyrighted material, are available for inspection and copying at the OSHA Docket Office. Information on using the *http://www.regulations.gov* Web site to submit comments and access the docket is available at the Web site's ''User Tips'' link. Contact the OSHA Docket Office for information about materials not available through the Web site, and for assistance in using the Internet to locate docket submissions.

Electronic copies of this **Federal Register** document are available at *http://www.regulations.gov*. This document as well as news releases and other relevant information also are available at OSHA's webpage at *http://www.osha.gov*.

V. Authority and Signature

Edwin G. Foulke, Jr., Assistant Secretary of Labor for Occupational Safety and Health, directed the preparation of this notice. The authority for this notice is the Paperwork Reduction Act of 1995 (44 U.S.C. 3506 *et seq.*) and Secretary of Labor's Order No. 5–2002 (67 FR 65008).

Signed at Washington, DC, on March 9, 2007.

Edwin G. Foulke, Jr.

Assistant Secretary of Labor.

[FR Doc. E7–4702 Filed 3–14–07; 8:45 am]

BILLING CODE 4510–26–P

NATIONAL TRANSPORTATION SAFETY BOARD

Sunshine Act Meeting; Notice

TIME AND DATE: 9:30 a.m., Tuesday, March 20, 2007. (The time of this meeting has changed to 12:30 p.m.)

PLACE: NTSB Conference Center, 429 L'Enfant Plaza SW., Washington, DC 20594.

STATUS: The two items are open to the public.

MATTERS TO BE CONSIDERED:

7870: *Railroad Accident Report*—Collision Of Two CN Freight Trains, Anding, Mississippi, July 10, 2005 (DCA–05–MR–011).

7834A: *Marine Accident Brief and Safety Recommendation Letter*—Fire on Board U.S. Small Passenger Vessel Massachusetts, Boston Harbor, Massachusetts, June 12, 2006.

NEWS MEDIA CONTACT: Telephone: (202) 314–6100. Individuals requesting specific accommodations should contact Chris Bisett at (202) 314–6305 by Friday, March 16, 2007.

The public may view the meting via alive or archived Webcast by accessing a link under ''News & Events'' on the NTSB home page at *http://www.ntsb.gov.*

FOR FURTHER INFORMATION CONTACT: Vicky D' Onofrio, (202) 314–6410.

Dated: March 13, 2007.

Candi R. Bing,

Federal Register Alternate Liaison Officer.

[FR Doc. 07–1283 Filed 3–13–07; 12:38 pm]

BILLING CODE 7533–01–M

NUCLEAR REGULATORY COMMISSION

[Docket No. 70–1257]

Notice of License Renewal Request of AREVA NP, Richland, WA, and Opportunity To Request a Hearing

AGENCY: Nuclear Regulatory Commission.

ACTION: Notice of license renewal application, and opportunity to request a hearing.

DATES: A request for a hearing must be filed by May 14, 2007.

FOR FURTHER INFORMATION CONTACT: Merritt Baker, Project Manager, Fuel Facility Licensing Directorate, Division of Fuel Cycle Safety and Safeguards, Office of Nuclear Material Safety and Safeguards, U.S. Nuclear Regulatory Commission, Washington, DC 20555. *Telephone:* (301) 415–6155; *fax number:* (301) 415–5955; *e-mail: mnb@nrc.gov*.

SUPPLEMENTARY INFORMATION:

I. Introduction

The U.S. Nuclear Regulatory Commission (NRC) has received, by letter dated October 24, 2006, a license renewal application from AREVA NP, Inc. (AREVA), requesting renewal of License No. SNM–1227 at its Richland fuel fabrication facility located in Richland, Washington. License No. SNM–1227 authorizes the licensee to possess and use special nuclear material for the manufacture of fuel for nuclear power plants.

The Richland facility has been licensed by the Atomic Energy Commission and its successor, the NRC, to manufacture low-enriched uranium fuel for nuclear power plants. The license was renewed in 1996 for a period of 10 years, expiring on November 30, 2006. By applications dated October 24 and December 13, 2006, AREVA requested renewal of their license for a period of 40 years. The NRC will review the license renewal application for compliance with applicable sections of regulations in Title 10 of the Code of Federal Regulations (10 CFR)—Energy, Chapter I—Nuclear Regulatory Commission. The license renewal application included an Environmental Report, which the NRC will review and use to prepare an environmental assessment to assist in the NRC's determination on the license renewal application, as required by 10 CFR Part 51, Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions, and the National Environmental Policy Act.

An NRC administrative review, documented in a letter to AREVA dated February 7, 2007, (ML070320061) found the application acceptable to begin a technical review. Because AREVA filed the application for renewal not less than 30 days before the expiration of the date stated in the existing license, the existing license will not expire until the Commission makes a final determination on the renewal application, in accordance with the timely renewal provision of 10 CFR 70.38(a)(1). If the NRC approves the renewal application, the approval will be documented in NRC License No. SNM–1227. However, before approving the proposed renewal, the NRC will need to make the findings required by the Atomic Energy Act of 1954, as amended, and NRC's regulations. These findings will be documented in a Safety Evaluation Report and an Environmental Assessment and/or an Environmental Impact Statement.

II. Opportunity To Request a Hearing

The NRC hereby provides notice that this is a proceeding on an application for a license renewal. In accordance with the general requirements in subpart C of 10 CFR part 2, as amended on January 14, 2004 (69 FR 2182), any person whose interest may be affected by this proceeding and who desires to participate as a party must file a written request for a hearing and a specification of the contentions which the person seeks to have litigated in the hearing.

In accordance with 10 CFR 2.302(a), a request for a hearing must be filed with the Commission either by:

1. *First class mail addressed to:* Office of the Secretary, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, *Attention:* Rulemakings and Adjudications Staff;

2. *Courier, express mail, and expedited delivery services:* Office of the Secretary, Sixteenth Floor, One White Flint North, 11555 Rockville Pike, Rockville, MD 20852, Attention: Rulemakings and Adjudications Staff, between 7:45 a.m. and 4:15 p.m., Federal workdays;

3. E-mail addressed to the Office of the Secretary, U.S. Nuclear Regulatory Commission, *hearingdocket@nrc.gov;* or

4. By facsimile transmission addressed to the Office of the Secretary, U.S. Nuclear Regulatory Commission, Washington, DC, Attention: Rulemakings and Adjudications Staff, at (301) 415–1101; verification number is (301) 415–1966.

In accordance with 10 CFR 2.302(b), all documents offered for filing must be accompanied by proof of service on all parties to the proceeding or their attorneys of record as required by law or by rule or order of the Commission, including:

1. The applicant, AREVA NP, Inc. 2101 Horn Rapids Road, Richland Washington, 99254, *Attention:* Robert Link; and

2. The NRC staff, by delivery to the Office of the General Counsel, One White Flint North, 11555 Rockville Pike, Rockville, MD 20852, or by mail addressed to the Office of the General Counsel, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001. Hearing requests should also be transmitted to the Office of the General Counsel, either by means of facsimile transmission to (301) 415–3725, or via email to *ogcmailcenter@nrc.gov*.

The formal requirements for documents contained in 10 CFR 2.304 (b), (c), (d), and (e), must be met. In accordance with 10 CFR 2.304(f), a document filed by electronic mail or facsimile transmission need not comply with the formal requirements of 10 CFR 2.304 (b), (c), and (d), as long as an original and two (2) copies otherwise complying with all of the requirements of 10 CFR 2.304 (b), (c), and (d) are mailed within two (2) days thereafter to the Secretary, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, *Attention:* Rulemakings and Adjudications Staff.

In accordance with 10 CFR 2.309(b), a request for a hearing must be filed by May 14, 2007.

In addition to meeting other applicable requirements of 10 CFR 2.309, the general requirements involving a request for a hearing filed by a person other than an applicant must state:

1. The name, address, and telephone number of the requester;

2. The nature of the requester's right under the Act to be made a party to the proceeding;

3. The nature and extent of the requester's property, financial or other interest in the proceeding;

4. The possible effect of any decision or order that may be issued in the proceeding on the requester's interest; and

5. The circumstances establishing that the request for a hearing is timely in accordance with 10 CFR 2.309(b).

In accordance with 10 CFR 2.309(f)(1), a request for hearing or petitions for leave to intervene must set forth with particularity the contentions sought to be raised. For each contention, the request or petition must:

1. Provide a specific statement of the issue of law or fact to be raised or controverted;

2. Provide a brief explanation of the basis for the contention;

3. Demonstrate that the issue raised in the contention is within the scope of the proceeding;

4. Demonstrate that the issue raised in the contention is material to the findings that the NRC must make to support the action that is involved in the proceeding;

5. Provide a concise statement of the alleged facts or expert opinions which support the requester's/petitioner's position on the issue and on which the requester/petitioner intends to rely to support its position on the issue; and

6. Provide sufficient information to show that a genuine dispute exists with the applicant on a material issue of law or fact. This information must include references to specific portions of the application (including the applicant's environmental report and safety report) that the requester/petitioner disputes and the supporting reasons for each dispute, or, if the requester/petitioner believes the application fails to contain information on a relevant matter as required by law, the identification of each failure and the supporting reasons for the requester's/petitioner's belief.

In addition, in accordance with 10 CFR 2.309(f)(2), contentions must be based on documents or other information available at the time the petition is to be filed, such as the application, supporting safety analysis report, environmental report or other supporting documents filed by an applicant or licensee, or otherwise available to the petitioner. On issues arising under the National Environmental Policy Act, the requester/petitioner shall file contentions based on the applicant's environmental report. The requester/petitioner may amend those contentions or file new contentions if there are data or conclusions in the NRC draft, or final environmental impact statement, environmental assessment, or any supplements relating thereto, that differ significantly from the data or conclusions in the applicant's documents. Otherwise, contentions may be amended or new contentions filed after the initial filing only with leave of the presiding officer.

Each contention shall be given a separate numeric or alpha designation within one of the following groups:

1. Technical—primarily concerns issues relating to matters discussed or referenced in the Safety Evaluation Report for the proposed action.

2. Environmental—primarily concerns issues relating to matters discussed or referenced in the Environmental Report for the proposed action.

3. Emergency Planning—primarily concerns issues relating to matters discussed or referenced in the Emergency Plan as it relates to the proposed action.

4. Physical Security—primarily concerns issues relating to matters discussed or referenced in the Physical Security Plan as it relates to the proposed action.

5. Miscellaneous—does not fall into one of the categories outlined above.

If the requester/petitioner believes a contention raises issues that cannot be classified as primarily falling into one of these categories, the requester/petitioner must set forth the contention and supporting bases, in full, separately for each category into which the requester/petitioner asserts the contention belongs with a separate designation for that category.

Requesters/petitioners should, when possible, consult with each other in preparing contentions and combine similar subject matter concerns into a

joint contention, for which one of the co-sponsoring requesters/petitioners is designated the lead representative. Further, in accordance with 10 CFR 2.309(f)(3), any requester/petitioner that wishes to adopt a contention proposed by another requester/petitioner must do so in writing within ten days of the date the contention is filed, and designate a representative who shall have the authority to act for the requester/petitioner.

In accordance with 10 CFR 2.309(g), a request for hearing and/or petition for leave to intervene may also address the selection of the hearing procedures, taking into account the provisions of 10 CFR 2.310.

III. Further Information

Documents related to this action, including the application for amendment and supporting documentation, are available electronically at the NRC's Electronic Reading Room at *http://www.nrc.gov/reading-rm/adams.html*. From this site, you can access the NRC's Agencywide Documents Access and Management System (ADAMS), which provides text and image files of NRC's public documents. The ADAMS accession numbers for the documents related to this notice are:

Document	ADAMS Accession No.	Date
Transmittal letter	ML063110083	10/24/06
License renewal application public version	ML063110089	10/24/06
Environmental Report	ML063110087	10/31/06
Additional information	ML063530128	12/13/06
NRC acceptance letter	ML070320061	02/07/07

If you do not have access to ADAMS or if there are problems in accessing the documents located in ADAMS, contact the NRC Public Document Room (PDR) Reference staff at 1–800–397–4209, 301–415–4737, or by e-mail to *pdr@nrc.gov*.

These documents may also be viewed electronically on the public computers located at the NRC's PDR, O–1–F21, One White Flint North, 11555 Rockville Pike, Rockville, MD 20852. The PDR reproduction contractor will copy documents for a fee.

Dated at Rockville, Maryland, this 8th day of March, 2007.

For the U.S. Nuclear Regulatory Commission.

Gary Janosko,

Deputy Director, Fuel Facility Licensing Directorate, Division of Fuel Cycle Safety and Safeguards, Office of Nuclear Material Safety And Safeguards.

[FR Doc. E7–4750 Filed 3–14–07; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

[Docket No. 70–3098]

Notice of License Application for Possession and Use of Byproduct, Source, and Special Nuclear Materials for the Mixed Oxide Fuel Fabrication Facility, Aiken, SC, and Opportunity To Request a Hearing

AGENCY: Nuclear Regulatory Commission.

ACTION: Notice of license application, and opportunity to request a hearing.

DATES: A request for a hearing must be filed by May 14, 2007.

FOR FURTHER INFORMATION CONTACT: David Tiktinsky, Senior Project Manager, MOX Branch, Division of Fuel Cycle Safety and Safeguards, Office of Nuclear Material Safety and Safeguards, U.S. Nuclear Regulatory Commission, Washington, DC 20555. *Telephone:* (301) 415–6195; *fax number:* (301) 415–5369; *e-mail: dht@nrc.gov*.

SUPPLEMENTARY INFORMATION:

I. Introduction

The Nuclear Regulatory Commission (NRC) has received, by letter dated September 27, 2006, November 16, 2006 (document withheld based on 10 CFR 2.390), and January 4, 2007 (a public redacted version), a license application and supporting documents from Shaw AREVA MOX Services (MOX Services), requesting a license for possession and use of byproduct, source, and special nuclear materials for the Mixed Oxide Fuel Fabrication Facility (MFFF) to be located on the Savannah River Site in Aiken, SC.

On March 30, 2005, the NRC issued a Construction Authorization (CA) to MOX Services (formerly known as Duke, Cogema, Stone and Webster) for a MFFF to be located at the Savannah River Site in Aiken, South Carolina (ML050660392).The NRC staff's technical basis for issuing the CA was set forth in NUREG–1821, ''Final Safety Evaluation Report on the Construction Authorization Request for the Mixed Oxide Fuel Fabrication Facility at the Savannah River Site, South Carolina'' (ML050660399). The results of the staff's environmental review related to the issuance of the CA are contained in NUREG–1767, ''Environmental Impact Statement on the Construction and Operation of a Mixed Oxide Fuel Fabrication Facility at the Savannah River Site, South Carolina—Final Report'' (ML050240233, ML050240250).

A License Application (LA) was submitted to the NRC on September 27, 2006, requesting the approval for the possession and use of byproduct, source, and special nuclear materials for the MFFF. In the process of performing the Acceptance/Acknowledgment review of the LA, the staff identified some parts of the submittal that required modifications in order for the NRC to complete the initial review. The preliminary review of the LA indicated that much of the information required by Part 70 (in particular, 10 CFR 70.22 and 10 CFR part 70, subpart H) to be in an operating license application was contained in the Integrated Safety Analyses (ISA) Summary. The staff also believed that some of the information that was identified to be withheld as proprietary should be publically available.

On November 7, 2006, the NRC sent a letter to Mr. David Stinson, President of MOX Services indicating the modifications that were needed in order for the NRC to complete its initial Acceptance/Acknowledgment review. A revised LA was submitted to the NRC on November 16, 2006 (document was withheld under 10 CFR 2.390).

The U.S. NRC staff performed an acknowledgment/ acceptance review of the revised MFFF license submittals to determine if sufficient information was provided for the staff to begin a detailed technical review.

The submittals generally addressed the requirements of an operating license for a facility specified in 10 CFR part 70, and the items specified in NUREG–1718, ''Standard Review Plan for the Review of an Application for a Mixed Oxide Fuel Fabrication Facility.'' The staff accepted the application for technical review and docketing. The

Acceptance/Acknowledgment review was documented in a letter to MOX Services dated December 20, 2006 (ML063530612). A redacted public version of the LA was submitted to the NRC on January 4, 2007 (ML070160304 and ML070160311).

The NRC will review the license application for compliance with applicable sections of regulations in Title 10 of the Code of Federal Regulations (10 CFR)—Energy, Chapter I—Nuclear Regulatory Commission.

If the NRC approves the application, the approval will be documented in an NRC License. However, before approving the request for an operating license, the NRC will need to make the findings required by the Atomic Energy Act of 1954, as amended, and NRC's regulations. These findings will be documented in a Safety Evaluation Report.

II. Opportunity To Request a Hearing

The NRC hereby provides notice that this is a proceeding on an application for a license. In accordance with the general requirements in subpart C of 10 CFR part 2, as amended on January 14, 2004 (69 FR 2182), any person whose interest may be affected by this proceeding and who desires to participate as a party must file a written request for a hearing and a specification of the contentions which the person seeks to have litigated in the hearing.

In accordance with 10 CFR 2.302(a), a request for a hearing must be filed with the Commission either by:

1. *First class mail addressed to:* Office of the Secretary, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, *Attention:* Rulemakings and Adjudications Staff;

2. *Courier, express mail, and expedited delivery services:* Office of the Secretary, Sixteenth Floor, One White Flint North, 11555 Rockville Pike, Rockville, MD 20852, *Attention:* Rulemakings and Adjudications Staff, between 7:45 a.m. and 4:15 p.m., Federal workdays;

3. E-mail addressed to the Office of the Secretary, U.S. Nuclear Regulatory Commission, *hearingdocket@nrc.gov*; or

4. By facsimile transmission addressed to the Office of the Secretary, U.S. Nuclear Regulatory Commission, Washington, DC, *Attention:* Rulemakings and Adjudications Staff, at (301) 415–1101; verification number is (301) 415–1966.

In accordance with 10 CFR 2.302 (b), all documents offered for filing must be accompanied by proof of service on all parties to the proceeding or their attorneys of record as required by law or by rule or order of the Commission, including:

1. The applicant, Shaw AREVA MOX Services, P.O. Box 7097, Aiken, SC 29804, *Attention:* Dealis Gwyn; and

2. The NRC staff, by delivery to the Office of the General Counsel, One White Flint North, 11555 Rockville Pike, Rockville, MD 20852, or by mail addressed to the Office of the General Counsel, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001. Hearing requests should also be transmitted to the Office of the General Counsel, either by means of facsimile transmission to (301) 415–3725, or via e-mail to *ogcmailcenter@nrc.gov*.

The formal requirements for documents contained in 10 CFR 2.304(b), (c), (d), and (e), must be met. In accordance with 10 CFR 2.304(f), a document filed by electronic mail or facsimile transmission need not comply with the formal requirements of 10 CFR 2.304(b), (c), and (d), as long as an original and two (2) copies otherwise complying with all of the requirements of 10 CFR 2.304(b), (c), and (d) are mailed within two (2) days thereafter to the Secretary, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, Attention: Rulemakings and Adjudications Staff.

In accordance with 10 CFR 2.309 (b), a request for a hearing must be filed by May 14, 2007.

In addition to meeting other applicable requirements of 10 CFR 2.309, the general requirements involving a request for a hearing filed by a person other than an applicant must state:

1. The name, address, and telephone number of the requester;

2. The nature of the requester's right under the Act to be made a party to the proceeding;

3. The nature and extent of the requester's property, financial or other interest in the proceeding;

4. The possible effect of any decision or order that may be issued in the proceeding on the requester's interest; and

5. The circumstances establishing that the request for a hearing is timely in accordance with 10 CFR 2.309 (b).

In accordance with 10 CFR 2.309 (f)(1), a request for hearing or petitions for leave to intervene must set forth with particularity the contentions sought to be raised. For each contention, the request or petition must:

1. Provide a specific statement of the issue of law or fact to be raised or controverted;

2. Provide a brief explanation of the basis for the contention;

3. Demonstrate that the issue raised in the contention is within the scope of the proceeding;

4. Demonstrate that the issue raised in the contention is material to the findings that the NRC must make to support the action that is involved in the proceeding;

5. Provide a concise statement of the alleged facts or expert opinions which support the requester's/petitioner's position on the issue and on which the requester/petitioner intends to rely to support its position on the issue; and

6. Provide sufficient information to show that a genuine dispute exists with the applicant on a material issue of law or fact. This information must include references to specific portions of the application that the requester/petitioner disputes and the supporting reasons for each dispute, or, if the requester/petitioner believes the application fails to contain information on a relevant matter as required by law, the identification of each failure and the supporting reasons for the requester's/petitioner's belief.

In addition, in accordance with 10 CFR 2.309 (f)(2), contentions must be based on documents or other information available at the time the petition is to be filed, such as the application, supporting safety analysis report, or other supporting documents filed by an applicant or licensee, or otherwise available to the petitioner.

Each contention shall be given a separate numeric or alpha designation within one of the following groups:

1. Technical—primarily concerns issues relating to matters discussed or referenced in the Safety Evaluation Report for the proposed action.

2. Environmental—primarily concerns issues relating to matters discussed or referenced in the Environmental Report for the proposed action.

3. Emergency Planning—primarily concerns issues relating to matters discussed or referenced in the Emergency Plan as it relates to the proposed action.

4. Physical Security—primarily concerns issues relating to matters discussed or referenced in the Physical Security Plan as it relates to the proposed action.

5. Miscellaneous—does not fall into one of the categories outlined above.

If the requester/petitioner believes a contention raises issues that cannot be classified as primarily falling into one of these categories, the requester/petitioner must set forth the contention and supporting bases, in full, separately for each category into which the requester/petitioner asserts the contention belongs

with a separate designation for that category.

Requesters/petitioners should, when possible, consult with each other in preparing contentions and combine similar subject matter concerns into a joint contention, for which one of the co-sponsoring requesters/petitioners is designated the lead representative. Further, in accordance with 10 CFR 2.309 (f)(3), any requester/petitioner that wishes to adopt a contention proposed by another requester/petitioner must do so in writing within ten days of the date the contention is filed, and designate a representative who shall have the authority to act for the requester/ petitioner.

In accordance with 10 CFR 2.309 (g), a request for hearing and/or petition for leave to intervene may also address the selection of the hearing procedures, taking into account the provisions of 10 CFR 2.310.

III. Further Information

Documents related to this action, including the application and supporting documentation, are available electronically at the NRC's Electronic Reading Room at *http://www.nrc.gov/reading-rm/adams.html*. From this site, you can access the NRC's Agencywide Document Access and Management System (ADAMS), which provides text and image files of NRC's public documents. The ADAMS accession numbers for the documents related to this notice are:

Document	ADAMS Accession No.	Date
License Application for the MFFF	ML062750194	09/27/2006
Request for exemption from decommissioning requirements	ML062720071	09/27/2006
Request for exemption from radiation labeling requirements	ML062720076	09/27/2006
Request for exemption from indemnity agreement and financial protection requirement	ML062720082	09/27/2006
NRC letter with comments on LA content review	ML063100216	11/07/2006
Emergency plan assessment	ML063250124 ML063250129	11/16/2007
NRC acceptance/acknowledgment review letter	ML063530612	12/20/2006
Transmittal letter for public version of LA	ML070160304	01/04/2007
License application public version	ML070160311	01/04/2007

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Dated at Rockville, Maryland, this 7th day of March, 2007.

For the Nuclear Regulatory Commission.

Joseph Giitter,

Director, Special Project, and Technical Support Directorate, Division of Fuel Cycle Safety and Safeguards, Office of Nuclear Material Safety and Safeguards.

[FR Doc. E7–4751 Filed 3–14–07; 8:45 am]

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NUCLEAR REGULATORY COMMISSION

[EA–07–055]

In the Matter of Holder of Material License Authorized To Use Sealed Sources in Panoramic and Underwater Irradiators and Possess Greater Than 370 Terabecquerels (10,000 Curies); Order Imposing Fingerprinting and Criminal History Records Check Requirements for Unescorted Access to Certain Radioactive Material (Effective Immediately)

I

The Licensee identified in Attachment 1 [1] to this Order holds a license issued in accordance with the Atomic Energy Act (AEA) of 1954, as amended, by the U.S. Nuclear Regulatory Commission (NRC or Commission) or Agreement States, authorizing possession of greater than 370 Terabecquerels (10,000 curies) of byproduct material, in the form of sealed sources, either in panoramic irradiators that have dry or wet storage of the sealed sources, or in underwater irradiators in which both the source and the product being irradiated are underwater. On August 8, 2005, the Energy Policy Act of 2005 (EPAct) was enacted. Section 652 of the EPAct amended Section 149 of the AEA to require fingerprinting and a Federal Bureau of Investigation (FBI) identification and criminal history records check of any person who is permitted unescorted access to radioactive materials subject to regulation by the Commission, and which the Commission determines to be of such significance to the public health and safety or the common defense and security as to warrant fingerprinting and background checks. NRC has decided to implement this requirement, in part, prior to the completion of the rulemaking to implement the provisions under the EPAct, which is underway, because a deliberate malevolent act by an individual with unescorted access to these radioactive materials has a potential to result in significant adverse impacts to the public health and safety or the common defense and security. Those exempted, from fingerprinting requirements under 10 CFR 73.61 (72 FR 4945 (February 2, 2007)) are also exempt from the fingerprinting requirements under this Order. In addition, individuals who have a favorably-decided U.S. Government criminal history record check within the last five (5) years, or individuals who have an active federal security clearance (provided in each case that they make available the appropriate documentation), have satisfied the EPAct fingerprinting requirement and need not be fingerprinted again. Individuals who have been fingerprinted and granted access to

[1] Attachment 1 contains sensitive information and will not be released to the public.

Safeguards Information[2] (SGI) by the reviewing official under Order EA–06–242 do not need to be fingerprinted again.

II

Subsequent to the terrorist events of September 11, 2001, the NRC issued a security Order requiring certain large panoramic and underwater irradiator licensees to implement Compensatory Measures (CMs) for radioactive materials. The requirements imposed by Order EA–06–251 (Irradiator Order), and measures licensees have developed to comply with that Order, were designated by the NRC as SGI and were not released to the public. One specific CM imposed by the Irradiator Order required licensees to conduct local criminal history checks to determine the trustworthiness and reliability of individuals needing unescorted access to the panoramic or underwater irradiator sealed sources. ''Access'' means that an individual could exercise some physical control over the material or device. In accordance with Section 149 of the AEA, as amended by the EPAct, the Commission is imposing the FBI criminal history records check requirements, as set forth in this Order, including Attachment 2 to this Order, on the Licensee identified in Attachment 1 to this Order, that possesses greater than 370 Terabecquerels (10,000 curies) of byproduct material in the form of sealed sources. These requirements will remain in effect until the Commission determines otherwise.

In addition, pursuant to 10 CFR 2.202, find that in light of the common defense and security matters identified above, which warrant the issuance of this Order, the public health, safety, and interest require that this Order be effective immediately.

III

Accordingly, pursuant to Sections 81, 149, 161b, 161i, 161o, 182, and 186 of the AEA of 1954, as amended, and the Commission's regulations in 10 CFR 2.202, 10 CFR Part 30, and 10 CFR Part 36, *it is hereby ordered,* effective immediately, that the licensee identified in attachment 1 to this order shall comply with the requirements set forth in this order.

A. The licensee identified in Attachment 1 to this Order shall comply with the following requirements:

1. The Licensee shall, within twenty (20) days of the date of this Order, establish and maintain a fingerprinting program that meets the requirements of Attachment 2 to this Order, for unescorted access to the panoramic or underwater irradiator sealed sources.

2. The Licensee shall, in writing, within twenty (20) days of the date of this Order, notify the Commission (1) of receipt and confirmation that compliance with the Order will be achieved, or (2) if it is unable to comply with any of the requirements described in Attachment 2, or (3) if compliance with any of the requirements is unnecessary in its specific circumstances. The notification shall provide the Licensee's justification for seeking relief from, or variation of, any specific requirement.

B. In accordance with the NRC's ''Order Imposing Fingerprinting and Criminal History Check Requirements for Access to Safeguards Information'' (EA–06–242) issued on October 4, 2006, only the NRC-approved reviewing official shall review results from an FBI criminal history records check. The reviewing official shall determine whether an individual may have, or continue to have, unescorted access to the panoramic or underwater irradiator sealed sources that equal or exceed 370 Terabecquerels (10,000 curies). Fingerprinting and the FBI identification and criminal history records check are not required for individuals exempted from fingerprinting requirements under 10 CFR 73.61 [72 FR 4945 (February 2, 2007)]. In addition, individuals who have a favorably decided U.S. Government criminal history records check within the last five (5) years, or have an active federal security clearance (provided in each case that the appropriate documentation is made available to the Licensee's reviewing official), have satisfied the EPAct fingerprinting requirement and need not be fingerprinted again.

C. Fingerprints shall be submitted and reviewed in accordance with the procedures described in Attachment 2 to this Order. Individuals who have been fingerprinted and granted access to SGI by the reviewing official under Order EA–06–242 do not need to be fingerprinted again.

D. The Licensee may allow any individual who currently has unescorted access to the panoramic or underwater irradiator sealed sources, in accordance with the Irradiator Order, to continue to have unescorted access without being fingerprinted, pending a decision by the reviewing official (based on fingerprinting, an FBI criminal history records check and a trustworthy and reliability determination) that the individual may continue to have unescorted access to the panoramic or underwater irradiator sealed sources. The licensee shall complete implementation of the requirements of Attachment 2 to this Order by June 5, 2007.

Licensee responses to Condition A.2. shall be submitted to the Director, Office of Federal and State Materials and Environmental Management Programs, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001. In addition, Licensee responses shall be marked as ''Security-Related Information—Withhold Under 10 CFR 2.390.''

The Director, Office of Federal and State Materials and Environmental Management Programs, may, in writing, relax or rescind any of the above conditions upon demonstration of good cause by the Licensee.

IV

In accordance with 10 CFR 2.202, the Licensee must, and any other person adversely affected by this Order may, submit an answer to this Order, and may request a hearing on this Order, within twenty (20) days of the date of this Order. Where good cause is shown, consideration will be given to extending the time to request a hearing. A request for extension of time in which to submit an answer or request a hearing must be made in writing to the Director, Office of Federal and State Materials and Environmental Management Programs, U.S. Nuclear Regulatory Commission, Washington, DC 20555, and include a statement of good cause for the extension. The answer may consent to this Order. Unless the answer consents to this Order, the answer shall, in writing and under oath or affirmation, specifically set forth the matters of fact and law on which the Licensee or other person adversely affected relies and the reasons as to why the Order should not have been issued. Any answer or request for a hearing shall be submitted to the Secretary, Office of the Secretary, U.S. Nuclear Regulatory Commission, *ATTN:* Rulemakings and Adjudications Staff, Washington, DC 20555. Copies also shall be sent to the Director, Office of Federal and State Materials and Environmental Management Programs, U.S. Nuclear Regulatory Commission, Washington, DC 20555, to the Assistant General Counsel for Materials Litigation and Enforcement at the same address, and to the Licensee if the answer or hearing request is by a person other than the Licensee. Because of possible delays in delivery of mail to United States Government offices, it is requested that answers and requests for hearing be

[2] Safeguards Information is a form of sensitive, unclassified, security-related information that the Commission has the authority to designate and protect under section 147 of the AEA.

transmitted to the Secretary of the Commission either by means of facsimile transmission to (301) 415–1101, or by e-mail to *hearingdocket@nrc.gov* and also to the Office of the General Counsel, either by means of facsimile transmission to (301) 415–3725, or by e-mail to *OGCMailCenter@nrc.gov.* If a person other than the Licensee requests a hearing, that person shall set forth with particularity the manner in which his/her interest is adversely affected by this Order and shall address the criteria set forth in 10 CFR 2.309.

If a hearing is requested by the Licensee or a person whose interest is adversely affected, the Commission will issue an Order designating the time and place of any hearing. If a hearing is held, the issue to be considered at such hearing shall be whether this Order should be sustained.

Pursuant to 10 CFR 2.202(c)(2)(i), the Licensee may, in addition to demanding a hearing, at the time the answer is filed or sooner, move the presiding officer to set aside the immediate effectiveness of the Order on grounds that the Order, including the need for immediate effectiveness, is not based on adequate evidence, but on mere suspicion, unfounded allegations, or error.

In the absence of any request for hearing, or written approval of an extension of time in which to request a hearing, the provisions as specified above in Section III shall be final twenty (20) days from the date of this Order, without further Order or proceedings.

If an extension of time for requesting a hearing has been approved, the provisions as specified above in Section III shall be final when the extension expires, if a hearing request has not been received. An answer or a request for hearing shall not stay the immediate effectiveness of this order.

Dated this 8th day of March 2007.

For the Nuclear Regulatory Commission.

Charles L. Miller,

Director, Office of Federal and State Materials and Environmental Management Programs.

Attachment 1: List of Applicable Materials Licenses—Redacted.

Attachment 2: Requirements for Fingerprinting and Criminal History Checks of Individuals When Licensee's Reviewing Official is Determining Unescorted Access to the Panoramic or Underwater Irradiator Sealed Sources Subject to EA–07–055.

Requirements for Fingerprinting and Criminal History Checks of Individuals When Licensee's Reviewing Official Is Determining Unescorted Access to the Panoramic or Underwater Irradiator Sealed Sources Subject to EA–07–055

General Requirements

Licensees shall comply with the following requirements of this attachment.

1. Each Licensee subject to the provisions of this attachment shall fingerprint each individual who is seeking or permitted unescorted access to the panoramic or underwater irradiator sealed sources. The Licensee shall review and use the information received from the Federal Bureau of Investigation (FBI) and ensure that the provisions contained in the subject Order and this attachment are satisfied.

2. The Licensee shall notify each affected individual that the fingerprints will be used to secure a review of his/her criminal history record and inform the individual of the procedures for revising the record or including an explanation in the record, as specified in the ''Right to Correct and Complete Information'' section of this attachment.

3. Fingerprints for unescorted access need not be taken if an employed individual (e.g., a Licensee employee, contractor, manufacturer, or supplier) is relieved from the fingerprinting requirement by 10 CFR 73.61 for unescorted access, has a favorably-decided U.S. Government criminal history check within the last five (5) years, or has an active federal security clearance. Written confirmation from the Agency/employer which granted the federal security clearance or reviewed the criminal history check must be provided for either of the latter two cases. The Licensee must retain this documentation for a period of three (3) years from the date the individual no longer requires unescorted access to radioactive materials associated with the Licensee's activities.

4. All fingerprints obtained by the Licensee pursuant to this Order must be submitted to the Commission for transmission to the FBI.

5. The Licensee shall review the information received from the FBI and consider it, in conjunction with the trustworthy and reliability requirements of the Irradiator Order, in making a determination whether to grant, or continue to allow, unescorted access to radioactive materials.

6. The Licensee shall use any information obtained as part of a criminal history records check solely for the purpose of determining an individual's suitability for unescorted access to the panoramic or underwater irradiator sealed sources.

7. The Licensee shall document the basis for its determination whether to grant, or continue to allow, unescorted access to the panoramic or underwater irradiator sealed sources.

Prohibitions

A Licensee shall not base a final determination to deny an individual access to radioactive materials solely on the basis of information received from the FBI involving: an arrest more than one (1) year old for which there is no information of the disposition of the case, or an arrest that resulted in dismissal of the charge or an acquittal.

A Licensee shall not use information received from a criminal history check obtained pursuant to this Order in a manner that would infringe upon the rights of any individual under the First Amendment to the Constitution of the United States, nor shall the Licensee use the information in any way which would discriminate among individuals on the basis of race, religion, national origin, sex, or age.

Procedures for Processing Fingerprint Checks

For the purpose of complying with this Order, Licensees shall, using an appropriate method listed in 10 CFR 73.4, submit to the NRC's Division of Facilities and Security, Mail Stop T–6E46, one completed, legible standard fingerprint card (Form FD–258, ORIMDNRCOOOZ) or, where practicable, other fingerprint records for each individual seeking unescorted access to the panoramic or underwater irradiator sealed sources, to the Director of the Division of Facilities and Security, marked for the attention of the Division's Criminal History Check Section. Copies of these forms may be obtained by writing the Office of Information Services, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, by calling (301) 415–5877, or by e-mail to *forms@nrc.gov*. Practicable alternative formats are set forth in 10 CFR 73.4. The Licensee shall establish procedures to ensure that the quality of the fingerprints taken results in minimizing the rejection rate of fingerprint cards due to illegible or incomplete cards.

The NRC will review submitted fingerprint cards for completeness. Any Form FD–258 fingerprint record containing omissions or evident errors will be returned to the Licensee for corrections. The fee for processing fingerprint checks includes one re-submission if the initial submission is returned by the FBI because the

fingerprint impressions cannot be classified. The one free re-submission must have the FBI Transaction Control Number reflected on the re-submission. If additional submissions are necessary, they will be treated as initial submittals and will require a second payment of the processing fee.

Fees for processing fingerprint checks are due upon application. Licensees shall submit payment with the application for processing fingerprints by corporate check, certified check, cashier's check, money order, or electronic payment, made payable to ''U.S. NRC.'' [For guidance on making electronic payments, contact the Facilities Security Branch, Division of Facilities and Security, at (301) 415–7404]. Combined payment for multiple applications is acceptable. The application fee (currently $27) is the sum of the user fee charged by the FBI for each fingerprint card or other fingerprint record submitted by the NRC on behalf of a Licensee, and an NRC processing fee, which covers administrative costs associated with NRC handling of Licensee fingerprint submissions. The Commission will directly notify Licensees who are subject to this regulation of any fee changes.

The Commission will forward to the submitting Licensee all data received from the FBI as a result of the Licensee's application(s) for criminal history checks, including the FBI fingerprint record.

Right To Correct and Complete Information

Prior to any final adverse determination, the Licensee shall make available to the individual the contents of any criminal records obtained from the FBI for the purpose of assuring correct and complete information. Written confirmation by the individual of receipt of this notification must be maintained by the Licensee for a period of one (1) year from the date of the notification.

If, after reviewing the record, an individual believes that it is incorrect or incomplete in any respect and wishes to change, correct, or update the alleged deficiency, or to explain any matter in the record, the individual may initiate challenge procedures. These procedures include either direct application by the individual challenging the record to the agency (i.e., law enforcement agency) that contributed the questioned information, or direct challenge as to the accuracy or completeness of any entry on the criminal history record to the Assistant Director, Federal Bureau of Investigation Identification Division, Washington, DC 20537–9700 (as set forth in 28 CFR part 16.30 through 16.34). In the latter case, the FBI forwards the challenge to the agency that submitted the data and requests that agency to verify or correct the challenged entry. Upon receipt of an official communication directly from the agency that contributed the original information, the FBI Identification Division makes any changes necessary in accordance with the information supplied by that agency. The Licensee must provide at least ten (10) days for an individual to initiate an action challenging the results of an FBI criminal history records check after the record is made available for his/her review. The Licensee may make a final determination on unescorted access to the panoramic or underwater irradiator sealed sources based upon the criminal history record only upon receipt of the FBI's ultimate confirmation or correction of the record. Upon a final adverse determination on unescorted access to the panoramic or underwater irradiator sealed sources, the Licensee shall provide the individual its documented basis for denial. Unescorted access to the panoramic or underwater irradiator sealed sources shall not be granted to an individual during the review process.

Protection of Information

1. Each Licensee who obtains a criminal history record on an individual pursuant to this Order shall establish and maintain a system of files and procedures for protecting the record and the personal information from unauthorized disclosure.

2. The Licensee may not disclose the record or personal information collected and maintained to persons other than the subject individual, his/her representative, or to those who have a need to access the information in performing assigned duties in the process of determining unescorted access to the panoramic or underwater irradiator sealed sources. No individual authorized to have access to the information may re-disseminate the information to any other individual who does not have a need-to-know.

3. The personal information obtained on an individual from a criminal history record check may be transferred to another Licensee if the Licensee holding the criminal history record receives the individual's written request to re-disseminate the information contained in his/her file, and the gaining Licensee verifies information such as the individual's name, date of birth, social security number, sex, and other applicable physical characteristics for identification purposes.

4. The Licensee shall make criminal history records, obtained under this section, available for examination by an authorized representative of the NRC to determine compliance with the regulations and laws.

5. The Licensee shall retain all fingerprint and criminal history records received from the FBI, or a copy if the individual's file has been transferred, for three (3) years after termination of employment or denial to unescorted access to the panoramic or underwater irradiator sealed sources. After the required three (3) year period, these documents shall be destroyed by a method that will prevent reconstruction of the information in whole or in part.

[FR Doc. E7–4735 Filed 3–14–07; 8:45 am]
BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

[EA–07–051]

In the Matter of All Licensees Identified in Attachment 1 to Order EA–07–050 and All Other Persons Who Seek or Obtain Access to Safeguards Information Described Herein; Order Imposing Fingerprinting and Criminal History Records Check Requirements for Access to Safeguards Information (Effective Immediately)

I

The Licensees identified in Attachment 1 [1] to Order EA–07–050 are applicants for, or hold licenses issued in accordance with the Atomic Energy Act (AEA) of 1954, as amended, by the U.S. Nuclear Regulatory Commission (NRC or Commission) or Agreement States, authorizing them to engage in an activity subject to regulation by the Commission or Agreement States. On August 8, 2005, the Energy Policy Act of 2005 (EPAct) was enacted. Section 652 of the EPAct amended Section 149 of the AEA to require fingerprinting and a Federal Bureau of Investigation (FBI) identification and criminal history records check of any person who is to be permitted to have access to Safeguards Information (SGI).[2] The NRC's implementation of this requirement cannot await the completion of the SGI rulemaking,

[1] Attachment 1 to Order EA–07–050 contains sensitive information and will not be released to the public.

[2] Safeguards Information is a form of sensitive, unclassified, security-related information that the Commission has the authority to designate and protect under section 147 of the AEA.

which is underway, because the EPAct fingerprinting and criminal history records check requirements for access to SGI were immediately effective upon enactment of the EPAct. Although the EPAct permits the Commission by rule to except certain categories of individuals from the fingerprinting requirement, which the Commission has done [see 10 CFR part 73.59, 71 FR 33,989 (June 13, 2006))], it is unlikely that licensee employees or others are excepted from the fingerprinting requirement by the ''fingerprinting relief'' rule. Individuals relieved from fingerprinting and criminal history records checks under the relief rule include Federal, State, and local officials and law enforcement personnel; Agreement State inspectors who conduct security inspections on behalf of the NRC; members of Congress and certain employees of members of Congress or Congressional Committees, and representatives of the International Atomic Energy Agency (IAEA) or certain foreign government organizations. In addition, individuals who have a favorably-decided U.S. Government criminal history records check within the last five (5) years, or individuals who have active Federal security clearances (provided in either case that they make available the appropriate documentation), have satisfied the EPAct fingerprinting requirement and need not be fingerprinted again. Therefore, in accordance with Section 149 of the AEA, as amended by the EPAct, the Commission is imposing additional requirements for access to SGI, as set forth by this Order, so that affected licensees can obtain and grant access to SGI. This Order also imposes requirements for access to SGI by any person, from any person,[3] whether or not a Licensee, Applicant, or Certificate Holder of the Commission or Agreement States.

II

The Commission has broad statutory authority to protect and prohibit the unauthorized disclosure of SGI. Section 147 of the AEA grants the Commission explicit authority to issue such Orders as necessary to prohibit the unauthorized disclosure of SGI. Furthermore, Section 652 of the EPAct amended Section 149 of the AEA to require fingerprinting and an FBI identification and a criminal history records check of each individual who seeks access to SGI. In addition, no person may have access to SGI unless the person has an established need-to-know the information and satisfies the trustworthy and reliability requirements described in Attachment 3 to Order EA–07–050.

In order to provide assurance that the Licensees identified in Attachment 1 to Order EA–07–050 are implementing appropriate measures to comply with the fingerprinting and criminal history records check requirements for access to SGI, all Licensees identified in Attachment 1 to Order EA–07–050 shall implement the requirements of this Order. In addition, pursuant to 10 CFR 2.202, I find that in light of the common defense and security matters identified above, which warrant the issuance of this Order, the public health, safety and interest require that this Order be effective immediately.

III

Accordingly, pursuant to Sections 81, 147, 149, 161b, 161i, 161o, 182 and 186 of the Atomic Energy Act of 1954, as amended, and the Commission's regulations in 10 CFR 2.202, 10 CFR Parts 30 and 73, *it is hereby ordered*, effective immediately, that all licensees identified in attachment 1 to order EA–07–050 and all other persons who seek or obtain access to safeguards information, as described above, shall comply with the requirements set forth in this order.

A. 1. No person may have access to SGI unless that person has a need-to-know the SGI, has been fingerprinted or who has a favorably-decided FBI identification and criminal history records check, and satisfies all other applicable requirements for access to SGI. Fingerprinting and the FBI identification and criminal history records check are not required, however, for any person who is relieved from that requirement by 10 CFR 73.59 [(71 FR 33,989 (June 13, 2006))], or who has a favorably-decided U.S. Government criminal history records check within the last five (5) years, or who has an active Federal security clearance, provided in the latter two cases that the appropriate documentation is made available to the Licensee's NRC-approved reviewing official.

2. No person may have access to any SGI if the NRC has determined, based on fingerprinting and an FBI identification and criminal history records check, that the person may not have access to SGI.

B. No person may provide SGI to any other person except in accordance with Condition III.A. above. Prior to providing SGI to any person, a copy of this Order shall be provided to that person.

C. All Licensees identified in Attachment 1 to Order EA–07–050 shall comply with the following requirements:

1. The Licensee shall, within twenty (20) days of the date of this Order, establish and maintain a fingerprinting program that meets the requirements of Attachment 1 to this Order.

2. The Licensee shall, within twenty (20) days of the date of this Order, submit the fingerprints of one (1) individual who (a) the Licensee nominates as the ''reviewing official'' for determining access to SGI by other individuals, and (b) has an established need-to-know the information and has been determined to be trustworthy and reliable in accordance with the requirements described in Attachment 3 to Order EA–07–050. The NRC will determine whether this individual (or any subsequent reviewing official) may have access to SGI and, therefore, will be permitted to serve as the Licensee's reviewing official.[4] The Licensee may, at the same time or later, submit the fingerprints of other individuals to whom the Licensee seeks to grant access to SGI. Fingerprints shall be submitted and reviewed in accordance with the procedures described in Attachment 1 of this Order.

3. The Licensee shall, in writing, within twenty (20) days of the date of this Order, notify the Commission, (1) if it is unable to comply with any of the requirements described in this Order, including Attachment 1 to this Order, or (2) if compliance with any of the requirements is unnecessary in its specific circumstances. The notification shall provide the Licensee's justification for seeking relief from or variation of any specific requirement.

Licensee responses to C.1., C.2., and C.3. above shall be submitted to the Director, Office of Federal and State Materials and Environmental Management Programs, U.S. Nuclear Regulatory Commission, Washington, DC 20555. In addition, Licensee responses shall be marked as ''Security-

[3] Person means (1) any individual, corporation, partnership, firm, association, trust, estate, public or private institution, group, government agency other than the Commission or the Department of Energy, except that the Department of Energy shall be considered a person with respect to those facilities of the Department of Energy specified in section 202 of the Energy Reorganization Act of 1974 (88 Stat. 1244), any State or any political subdivision of, or any political entity within a State, any foreign government or nation or any political subdivision of any such government or nation, or other entity; and (2) any legal successor, representative, agent, or agency of the foregoing.

[4] The NRC's determination of this individual's access to SGI in accordance with the process described in Enclosure 5 to the transmittal letter of this Order is an administrative determination that is outside the scope of this Order.

Related Information—Withhold Under 10 CFR 2.390.''

The Director, Office of Federal and State Materials and Environmental Management Programs, may, in writing, relax or rescind any of the above conditions upon demonstration of good cause by the Licensee.

IV

In accordance with 10 CFR 2.202, the Licensee must, and any other person adversely affected by this Order may, submit an answer to this Order, and may request a hearing on this Order, within twenty (20) days of the date of this Order. Where good cause is shown, consideration will be given to extending the time to request a hearing. A request for extension of time in which to submit an answer or request a hearing must be made in writing to the Director, Office of Federal and State Materials and Environmental Management Programs, U.S. Nuclear Regulatory Commission, Washington, DC 20555, and include a statement of good cause for the extension. The answer may consent to this Order. Unless the answer consents to this Order, the answer shall, in writing and under oath or affirmation, specifically set forth the matters of fact and law on which the Licensee or other person adversely affected relies and the reasons as to why the Order should not have been issued. Any answer or request for a hearing shall be submitted to the Secretary, Office of the Secretary, U.S. Nuclear Regulatory Commission, *ATTN:* Rulemakings and Adjudications Staff, Washington, DC 20555. Copies also shall be sent to the Director, Office of Federal and State Materials and Environmental Management Programs, U.S. Nuclear Regulatory Commission, Washington, DC 20555, and to the Assistant General Counsel for Materials Litigation and Enforcement at the same address, and to the Licensee if the answer or hearing request is by a person other than the Licensee. Because of possible delays in delivery of mail to United States Government offices, it is requested that answers and requests for hearing be transmitted to the Secretary of the Commission either by means of facsimile transmission to 301–415–1101 or by e-mail to *hearingdocket@nrc.gov* and also to the Office of the General Counsel either by means of facsimile transmission to 301–415–3725 or by e-mail to *OGCMailCenter@nrc.gov*. If a person other than the Licensee requests a hearing, that person shall set forth with particularity the manner in which his/her interest is adversely affected by this Order and shall address the criteria set forth in 10 CFR 2.309.

If a hearing is requested by the Licensee or a person whose interest is adversely affected, the Commission will issue an Order designating the time and place of any hearing. If a hearing is held, the issue to be considered at such hearing shall be whether this Order should be sustained.

Pursuant to 10 CFR 2.202(c)(2)(i), the Licensee may, in addition to demanding a hearing, at the time the answer is filed or sooner, move the presiding officer to set aside the immediate effectiveness of the Order on the ground that the Order, including the need for immediate effectiveness, is not based on adequate evidence but on mere suspicion, unfounded allegations, or error. In the absence of any request for hearing, or written approval of an extension of time in which to request a hearing, the provisions as specified above in Section III shall be final twenty (20) days from the date of this Order without further order or proceedings. If an extension of time for requesting a hearing has been approved, the provisions as specified above in Section III shall be final when the extension expires if a hearing request has not been received. An answer or a request for hearing shall not stay the immediate effectiveness of this Order.

Dated this 8th day of March 2007.

For The Nuclear Regulatory Commission.

Charles L. Miller,

Director, Office of Federal and State Materials and Environmental Management Programs.

Attachment 1: Requirements for Fingerprinting and Criminal History Records Checks of Individuals When Licensee's Reviewing Official is Determining Access to Safeguards Information.

Requirements for Fingerprinting and Criminal History Records Checks of Individuals When Licensee's Reviewing Official is Determining Access to Safeguards Information.

General Requirements

Licensees shall comply with the requirements of this attachment.

A. 1. Each Licensee subject to the provisions of this attachment shall fingerprint each individual who is seeking or permitted access to Safeguards Information (SGI). The Licensee shall review and use the information received from the Federal Bureau of Investigation (FBI) and ensure that the provisions contained in the subject Order and this attachment are satisfied.

2. The Licensee shall notify each affected individual that the fingerprints will be used to secure a review of his/her criminal history record and inform the individual of the procedures for revising the record or including an explanation in the record, as specified in the ''Right to Correct and Complete Information'' section of this attachment.

3. Fingerprints need not be taken if an employed individual (e.g., a Licensee employee, contractor, manufacturer, or supplier) is relieved from the fingerprinting requirement by 10 CFR Part 73.59, has a favorably-decided U.S. Government criminal history records check within the last five (5) years, or has an active federal security clearance. Written confirmation from the Agency/employer which granted the federal security clearance or reviewed the criminal history records check must be provided. The Licensee must retain this documentation for a period of three (3) years from the date the individual no longer requires access to SGI associated with the Licensee's activities.

4. All fingerprints obtained by the Licensee pursuant to this Order must be submitted to the Commission for transmission to the FBI.

5. The Licensee shall review the information received from the FBI and consider it, in conjunction with the trustworthy and reliability requirements included in Attachment 3 to this Order, in making a determination whether to grant access to SGI to individuals who have a need-to-know the SGI.

6. The Licensee shall use any information obtained as part of a criminal history records check solely for the purpose of determining an individual's suitability for access to SGI.

7. The Licensee shall document the basis for its determination whether to grant access to SGI.

B. The Licensee shall notify the NRC of any desired change in reviewing officials. The NRC will determine whether the individual nominated as the new reviewing official may have access to SGI based on a previously-obtained or new criminal history check and, therefore, will be permitted to serve as the Licensee's reviewing official.

Prohibitions

A Licensee shall not base a final determination to deny an individual access to SGI solely on the basis of information received from the FBI involving: An arrest more than one (1) year old for which there is no information of the disposition of the case, or an arrest that resulted in dismissal of the charge or an acquittal.

A Licensee shall not use information received from a criminal history check obtained pursuant to this Order in a manner that would infringe upon the rights of any individual under the First

Amendment to the Constitution of the United States, nor shall the Licensee use the information in any way which would discriminate among individuals on the basis of race, religion, national origin, sex, or age.

Procedures for Processing Fingerprint Checks

For the purpose of complying with this Order, Licensees shall, using an appropriate method listed in 10 CFR part 73.4, submit to the NRC's Division of Facilities and Security, Mail Stop T–6E46, one completed, legible standard fingerprint card (Form FD–258, ORIMDNRCOOOZ) or, where practicable, other fingerprint records for each individual seeking access to Safeguards Information, to the Director of the Division of Facilities and Security, marked for the attention of the Division's Criminal History Check Section. Copies of these forms may be obtained by writing the Office of Information Services, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, by calling (301) 415–5877, or by e-mail to *forms@nrc.gov*. Practicable alternative formats are set forth in 10 CFR part 73.4. The Licensee shall establish procedures to ensure that the quality of the fingerprints taken results in minimizing the rejection rate of fingerprint cards due to illegible or incomplete cards.

The NRC will review submitted fingerprint cards for completeness. Any Form FD–258 fingerprint record containing omissions or evident errors will be returned to the Licensee for corrections. The fee for processing fingerprint checks includes one re-submission if the initial submission is returned by the FBI because the fingerprint impressions cannot be classified. The one free re-submission must have the FBI Transaction Control Number reflected on the re-submission. If additional submissions are necessary, they will be treated as initial submittals and will require a second payment of the processing fee.

Fees for processing fingerprint checks are due upon application. Licensees shall submit payment with the application for processing fingerprints by corporate check, certified check, cashier's check, money order, or electronic payment, made payable to ''U.S. NRC.'' [For guidance on making electronic payments, contact the Facilities Security Branch, Division of Facilities and Security, at (301) 415–7404]. Combined payment for multiple applications is acceptable. The application fee (currently $27) is the sum of the user fee charged by the FBI for each fingerprint card or other fingerprint record submitted by the NRC on behalf of a Licensee, and an NRC processing fee, which covers administrative costs associated with NRC handling of Licensee fingerprint submissions. The Commission will directly notify Licensees who are subject to this regulation of any fee changes.

The Commission will forward to the submitting Licensee all data received from the FBI as a result of the Licensee's application(s) for criminal history records checks, including the FBI fingerprint record.

Right To Correct and Complete Information

Prior to any final adverse determination, the Licensee shall make available to the individual the contents of any criminal records obtained from the FBI for the purpose of assuring correct and complete information. Written confirmation by the individual of receipt of this notification must be maintained by the Licensee for a period of one (1) year from the date of the notification. If, after reviewing the record, an individual believes that it is incorrect or incomplete in any respect and wishes to change, correct, or update the alleged deficiency, or to explain any matter in the record, the individual may initiate challenge procedures. These procedures include either direct application by the individual challenging the record to the agency (i.e., law enforcement agency) that contributed the questioned information, or direct challenge as to the accuracy or completeness of any entry on the criminal history record to the Assistant Director, Federal Bureau of Investigation Identification Division, Washington, DC 20537–9700 (as set forth in 28 CFR 16.30 through 16.34). In the latter case, the FBI forwards the challenge to the agency that submitted the data and requests that agency to verify or correct the challenged entry. Upon receipt of an official communication directly from the agency that contributed the original information, the FBI Identification Division makes any changes necessary in accordance with the information supplied by that agency. The Licensee must provide at least ten (10) days for an individual to initiate an action challenging the results of an FBI criminal history records check after the record is made available for his/her review. The Licensee may make a final SGI access determination based upon the criminal history record only upon receipt of the FBI's ultimate confirmation or correction of the record. Upon a final adverse determination on access to SGI, the Licensee shall provide the individual its documented basis for denial. Access to SGI shall not be granted to an individual during the review process.

Protection of Information

1. Each Licensee who obtains a criminal history record on an individual pursuant to this Order shall establish and maintain a system of files and procedures for protecting the record and the personal information from unauthorized disclosure.

2. The Licensee may not disclose the record or personal information collected and maintained to persons other than the subject individual, his/her representative, or to those who have a need to access the information in performing assigned duties in the process of determining access to Safeguards Information. No individual authorized to have access to the information may re-disseminate the information to any other individual who does not have a need-to-know.

3. The personal information obtained on an individual from a criminal history record check may be transferred to another Licensee if the Licensee holding the criminal history record check receives the individual's written request to re-disseminate the information contained in his/her file, and the gaining Licensee verifies information such as the individual's name, date of birth, social security number, sex, and other applicable physical characteristics for identification purposes.

4. The Licensee shall make criminal history records, obtained under this section, available for examination by an authorized representative of the NRC to determine compliance with the regulations and laws.

5. The Licensee shall retain all fingerprint and criminal history records received from the FBI, or a copy if the individual's file has been transferred, for 3 years after termination of employment or determination of access to SGI (whether access was approved or denied).

After the required 3-year period, these documents shall be destroyed by a method that will prevent reconstruction of the information in whole or in part.

[FR Doc. E7–4749 Filed 3–14–07; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

[EA–07–050]

In The Matter Of All Licensees Who Possess Radioactive Material In Quantities Of Concern And All Other Persons Who Obtain Safeguards Information Described Herein; Order Imposing Requirements for the Protection of Certain Safeguards Information (Effective Immediately)

The Licensees, identified in Attachment 1[1] to this Order, are applicants for or hold licenses issued in accordance with the Atomic Energy Act of 1954, by the U.S. Nuclear Regulatory Commission (NRC or Commission) or an Agreement State, authorizing them to possess, use, and transfer items containing radioactive material quantities of concern. NRC intends to issue security Orders to these licensees in the near future. Orders will be issued to both NRC and Agreement State materials licensees who may possess or transfer radioactive material quantities of concern. The Orders will require compliance with specific Compensatory Measures to enhance the security for certain radioactive material quantities of concern. The NRC will issue Orders to both NRC and Agreement State licensees under its authority to protect the common defense and security, which has not been relinquished to the Agreement States. The Commission has determined that these documents will contain Safeguards Information, will not be released to the public, and must be protected from unauthorized disclosure. Therefore, the Commission is imposing the requirements, as set forth in Attachments 2 and 3 to this Order and in Order EA–07–051, so that affected Licensees can receive these documents. This Order also imposes requirements for the protection of Safeguards Information in the hands of any person,[2] whether or not a licensee of the Commission, who produces, receives, or acquires Safeguards Information.

[1] Attachment 1 contains sensitive information and will not be released to the public.

[2] Person means (1) any individual, corporation, partnership, firm, association, trust, estate, public or private institution, group, government agency other than the Commission or the Department, except that the Department shall be considered a person with respect to those facilities of the Department specified in section 202 of the Energy Reorganization Act of 1974 (88 Stat. 1244), any State or any political subdivision of, or any political entity within a State, any foreign government or nation or any political subdivision of any such government or nation, or other entity; and (2) any legal successor, representative, agent, or agency of the foregoing.

II

The Commission has broad statutory authority to protect and prohibit the unauthorized disclosure of Safeguards Information. Section 147 of the Atomic Energy Act of 1954, as amended, grants the Commission explicit authority to "* * * issue such orders, as necessary to prohibit the unauthorized disclosure of safeguards information * * *" This authority extends to information concerning transfer of special nuclear material, source material, and byproduct material. Licensees and all persons who produce, receive, or acquire Safeguards Information must ensure proper handling and protection of Safeguards Information to avoid unauthorized disclosure in accordance with the specific requirements for the protection of Safeguards Information contained in Attachments 2 and 3 to this Order. The Commission hereby provides notice that it intends to treat violations of the requirements contained in Attachments 2 and 3 to this Order applicable to the handling and unauthorized disclosure of Safeguards Information as serious breaches of adequate protection of the public health and safety and the common defense and security of the United States. Access to Safeguards Information is limited to those persons who have established the need-to-know the information, are considered to be trustworthy and reliable, and meet the requirements of Order EA–07–051. A need-to-know means a determination by a person having responsibility for protecting Safeguards Information that a proposed recipient's access to Safeguards Information is necessary in the performance of official, contractual, or licensee duties of employment. Licensees and all other persons who obtain Safeguards Information must ensure that they develop, maintain and implement strict policies and procedures for the proper handling of Safeguards Information to prevent unauthorized disclosure, in accordance with the requirements in Attachments 2 and 3 to this Order. All licensees must ensure that all contractors whose employees may have access to Safeguards Information either adhere to the licensee's policies and procedures on Safeguards Information or develop, maintain and implement their own acceptable policies and procedures. The licensees remain responsible for the conduct of their contractors. The policies and procedures necessary to ensure compliance with applicable requirements contained in Attachments 2 and 3 to this Order must address, at a minimum, the following: the general performance requirement that each person who produces, receives, or acquires Safeguards Information shall ensure that Safeguards Information is protected against unauthorized disclosure; protection of Safeguards Information at fixed sites, in use and in storage, and while in transit; correspondence containing Safeguards Information; access to Safeguards Information; preparation, marking, reproduction and destruction of documents; external transmission of documents; use of automatic data processing systems; removal of the Safeguards Information category; the need-to-know the information; and background checks to determine access to the information.

In order to provide assurance that the licensees are implementing prudent measures to achieve a consistent level of protection to prohibit the unauthorized disclosure of Safeguards Information, all licensees who hold licenses issued by the NRC or an Agreement State authorizing them to possess and who may transport items containing radioactive material quantities of concern shall implement the requirements identified in Attachments 2 and 3 to this Order. The Commission recognizes that licensees may have already initiated many of the measures set forth in Attachments 2 and 3 to this Order for handling of Safeguards Information in conjunction with current NRC license requirements or previous NRC Orders. Additional measures set forth in Attachments 2 and 3 to this Order should be incorporated into the licensee's current program for Safeguards Information. In addition, pursuant to 10 CFR 2.202, I find that in light of the common defense and security matters identified above, which warrant the issuance of this Order, the public health, safety and interest require that this Order be effective immediately.

III

Accordingly, pursuant to Sections 81, 147, 161b, 161i, 161o, 182 and 186 of the Atomic Energy Act of 1954, as amended, and the Commission's regulations in 10 CFR 2.202, 10 CFR part 30, 10 CFR part 32, 10 CFR part 35, and 10 CFR part 70, *it is hereby ordered*, effective immediately, that all licensees identified in attachment 1 to this order and all other persons who produce, receive, or acquire the additional security measures identified above (whether draft or final) or any related safeguards information shall comply with the requirements of attachments 2 and 3 to this order.

The Director, Office of Federal and State Materials and Environmental Management Programs, may, in writing,

relax or rescind any of the above conditions upon demonstration of good cause by the licensee.

IV

In accordance with 10 CFR 2.202, the Licensee must, and any other person adversely affected by this Order may, submit an answer to this Order, and may request a hearing on this Order, within twenty (20) days of the date of this Order. Where good cause is shown, consideration will be given to extending the time to request a hearing. A request for extension of time in which to submit an answer or request a hearing must be made in writing to the Director, Office of Federal and State Materials and Environmental Management Programs, U.S. Nuclear Regulatory Commission, Washington, DC 20555, and include a statement of good cause for the extension. The answer may consent to this Order. Unless the answer consents to this Order, the answer shall, in writing and under oath or affirmation, specifically set forth the matters of fact and law on which the Licensee or other person adversely affected relies and the reasons as to why the Order should not have been issued. Any answer or request for a hearing shall be submitted to the Secretary, Office of the Secretary of the Commission, U.S. Nuclear Regulatory Commission, ATTN: Rulemakings and Adjudications Staff, Washington, DC 20555. Copies also shall be sent to the Director, Office of Nuclear Material Safety and Safeguards, U.S. Nuclear Regulatory Commission, Washington, DC 20555, to the Assistant General Counsel for Materials Litigation and Enforcement at the same address, and to the Licensee if the answer or hearing request is by a person other than the Licensee. Because of possible delays in delivery of mail to United States Government offices, it is requested that answers and requests for hearing be transmitted to the Secretary of the Commission either by means of facsimile transmission to 301–415–1101 or by e-mail to *hearingdocket@nrc.gov* and also to the Office of the General Counsel either by means of facsimile transmission to 301–415–3725 or by e-mail to *OGCMailCenter@nrc.gov*. If a person other than the Licensee requests a hearing, that person shall set forth with particularity the manner in which his interest is adversely affected by this Order and shall address the criteria set forth in 10 CFR 2.309.

If a hearing is requested by the Licensee or a person whose interest is adversely affected, the Commission will issue an Order designating the time and place of any hearing. If a hearing is held, the issue to be considered at such hearing shall be whether this Order should be sustained.

Pursuant to 10 CFR 2.202(c)(2)(i), the Licensee may, in addition to demanding a hearing, at the time the answer is filed or sooner, move the presiding officer to set aside the immediate effectiveness of the Order on the ground that the Order, including the need for immediate effectiveness, is not based on adequate evidence but on mere suspicion, unfounded allegations, or error. In the absence of any request for hearing, or written approval of an extension of time in which to request a hearing, the provisions specified in Section III above shall be final twenty (20) days from the date of this Order without further order or proceedings. If an extension of time for requesting a hearing has been approved, the provisions specified in Section III shall be final when the extension expires if a hearing request has not been received.

An answer or a request for hearing shall not stay the immediate effectiveness of this order.

Dated this 8th day of March 2007.

For The Nuclear Regulatory Commission.

Charles L. Miller,

Director, Office of Federal and State Materials and Environmental Management Programs.

Attachment 1: List of Applicable Materials Licensees Redacted.

Attachment 2: Modified Handling Requirements for the Protection of Certain Safeguards Information (SGI–M).

Modified Handling Requirements for the Protection of Certain Safeguards Information (SGI–M).

General Requirement

Information and material that the U.S. Nuclear Regulatory Commission (NRC) determines are safeguards information must be protected from unauthorized disclosure. In order to distinguish information needing modified protection requirements from the safeguards information for reactors and fuel cycle facilities that require a higher level of protection, the term ''Safeguards Information-Modified Handling'' (SGI–M) is being used as the distinguishing marking for certain materials licensees. Each person who produces, receives, or acquires SGI–M shall ensure that it is protected against unauthorized disclosure. To meet this requirement, licensees and persons shall establish and maintain an information protection system that includes the measures specified below. Information protection procedures employed by state and local police forces are deemed to meet these requirements.

Persons Subject to These Requirements

Any person, whether or not a licensee of the NRC, who produces, receives, or acquires SGI–M is subject to the requirements (and sanctions) of this document. Firms and their employees that supply services or equipment to materials licensees would fall under this requirement if they possess facility SGI–M. A licensee must inform contractors and suppliers of the existence of these requirements and the need for proper protection. (See more under Conditions for Access.)

State or local police units who have access to SGI–M are also subject to these requirements. However, these organizations are deemed to have adequate information protection systems. The conditions for transfer of information to a third party, i.e., need-to-know, would still apply to the police organization as would sanctions for unlawful disclosure. Again, it would be prudent for licensees who have arrangements with local police to advise them of the existence of these requirements.

Criminal and Civil Sanctions

The Atomic Energy Act of 1954, as amended, explicitly provides that any person, ''whether or not a licensee of the Commission, who violates any regulations adopted under this section shall be subject to the civil monetary penalties of section 234 of this Act.'' Furthermore, willful violation of any regulation or order governing safeguards information is a felony subject to criminal penalties in the form of fines or imprisonment, or both. See sections 147b. and 223 of the Act.

Conditions for Access

Access to SGI–M beyond the initial recipients of the order will be governed by the background check requirements imposed by the order. Access to SGI–M by licensee employees, agents, or contractors must include both an appropriate need-to-know determination by the licensee, as well as a determination concerning the trustworthiness of individuals having access to the information. Employees of an organization affiliated with the licensee's company, e.g., a parent company, may be considered as employees of the licensee for access purposes.

Need-to-Know

Need-to-know is defined as a determination by a person having responsibility for protecting SGI–M that a proposed recipient's access to SGI–M is necessary in the performance of official, contractual, or licensee duties

of employment. The recipient should be made aware that the information is SGI–M and those having access to it are subject to these requirements as well as criminal and civil sanctions for mishandling the information.

Occupational Groups

Dissemination of SGI–M is limited to individuals who have an established need-to-know and who are members of certain occupational groups. These occupational groups are:

A. An employee, agent, or contractor of an applicant, a licensee, the Commission, or the United States Government;

B. A member of a duly authorized committee of the Congress;

C. The Governor of a State or his designated representative;

D. A representative of the International Atomic Energy Agency (IAEA) engaged in activities associated with the U.S./IAEA Safeguards Agreement who has been certified by the NRC;

E. A member of a state or local law enforcement authority that is responsible for responding to requests for assistance during safeguards emergencies;

F. A person to whom disclosure is ordered pursuant to Section 2.744(e) of Part 2 of Part 10 of the Code of Federal Regulations; or,

G. State Radiation Control Program Directors (and State Homeland Security Directors) or their designees.

In a generic sense, the individuals described above in (A) through (G) are considered to be trustworthy by virtue of their employment status. For non-governmental individuals in group (A) above, a determination of reliability and trustworthiness is required. Discretion must be exercised in granting access to these individuals. If there is any indication that the recipient would be unwilling or unable to provide proper protection for the SGI–M, they are not authorized to receive SGI–M.

Information Considered for Safeguards Information Designation

Information deemed SGI–M is information the disclosure of which could reasonably be expected to have a significant adverse effect on the health and safety of the public or the common defense and security by significantly increasing the likelihood of theft, diversion, or sabotage of materials or facilities subject to NRC jurisdiction.

SGI–M identifies safeguards information which is subject to these requirements. These requirements are necessary in order to protect quantities of nuclear material significant to the health and safety of the public or common defense and security.

The overall measure for consideration of SGI–M is the usefulness of the information (security or otherwise) to an adversary in planning or attempting a malevolent act. The specificity of the information increases the likelihood that it will be useful to an adversary.

Protection While in Use

While in use, SGI–M shall be under the control of an authorized individual. This requirement is satisfied if the SGI–M is attended by an authorized individual even though the information is in fact not constantly being used. SGI–M, therefore, within alarm stations, continuously manned guard posts or ready rooms need not be locked in file drawers or storage containers.

Under certain conditions the general control exercised over security zones or areas would be considered to meet this requirement. The primary consideration is limiting access to those who have a need-to-know. Some examples would be:

Alarm stations, guard posts and guard ready rooms;

Engineering or drafting areas if visitors are escorted and information is not clearly visible;

Plant maintenance areas if access is restricted and information is not clearly visible;

Administrative offices (e.g., central records or purchasing) if visitors are escorted and information is not clearly visible.

Protection While in Storage

While unattended, SGI–M shall be stored in a locked file drawer or container. Knowledge of lock combinations or access to keys protecting SGI–M shall be limited to a minimum number of personnel for operating purposes who have a ''need-to-know'' and are otherwise authorized access to SGI–M in accordance with these requirements. Access to lock combinations or keys shall be strictly controlled so as to prevent disclosure to an unauthorized individual.

Transportation of Documents and Other Matter

Documents containing SGI–M when transmitted outside an authorized place of use or storage shall be enclosed in two sealed envelopes or wrappers. The inner envelope or wrapper shall contain the name and address of the intended recipient, and be marked both sides, top and bottom with the words ''Safeguards Information—Modified Handling.'' The outer envelope or wrapper must be addressed to the intended recipient, must contain the address of the sender, and must not bear any markings or indication that the document contains SGI–M.

SGI–M may be transported by any commercial delivery company that provides nationwide overnight service with computer tracking features, U.S. first class, registered, express, or certified mail, or by any individual authorized access pursuant to these requirements.

Within a facility, SGI–M may be transmitted using a single opaque envelope. It may also be transmitted within a facility without single or double wrapping, provided adequate measures are taken to protect the material against unauthorized disclosure. Individuals transporting SGI–M should retain the documents in their personal possession at all times or ensure that the information is appropriately wrapped and also secured to preclude compromise by an unauthorized individual.

Preparation and Marking of Documents

While the NRC is the sole authority for determining what specific information may be designated as ''SGI–M,'' originators of documents are responsible for determining whether those documents contain such information. Each document or other matter that contains SGI–M shall be marked ''Safeguards Information—Modified Handling'' in a conspicuous manner on the top and bottom of the first page to indicate the presence of protected information. The first page of the document must also contain (i) the name, title, and organization of the individual authorized to make a SGI–M determination, and who has determined that the document contains SGI–M, (ii) the date the document was originated or the determination made, (iii) an indication that the document contains SGI–M, and (iv) an indication that unauthorized disclosure would be subject to civil and criminal sanctions. Each additional page shall be marked in a conspicuous fashion at the top and bottom with letters denoting ''Safeguards Information—Modified Handling.''

In addition to the ''Safeguards Information—Modified Handling'' markings at the top and bottom of each page, transmittal letters or memoranda which do not in themselves contain SGI–M shall be marked to indicate that attachments or enclosures contain SGI–M but that the transmittal does not (e.g., ''When separated from SGI–M enclosure(s), this document is decontrolled'').

In addition to the information required on the face of the document, each item of correspondence that

contains SGI–M shall, by marking or other means, clearly indicate which portions (e.g., paragraphs, pages, or appendices) contain SGI–M and which do not. Portion marking is not required for physical security and safeguards contingency plans.

All documents or other matter containing SGI–M in use or storage shall be marked in accordance with these requirements. A specific exception is provided for documents in the possession of contractors and agents of licensees that were produced more than one year prior to the effective date of the order. Such documents need not be marked unless they are removed from file drawers or containers. The same exception applies to old documents stored away from the facility in central files or corporation headquarters.

Since information protection procedures employed by state and local police forces are deemed to meet NRC requirements, documents in the possession of these agencies need not be marked as set forth in this document.

Removal From SGI–M Category

Documents containing SGI–M shall be removed from the SGI–M category (decontrolled) only after the NRC determines that the information no longer meets the criteria of SGI–M. Licensees have the authority to make determinations that specific documents *which they created* no longer contain SGI–M information and may be decontrolled. Consideration must be exercised to ensure that any document decontrolled shall not disclose SGI–M in some other form or be combined with other unprotected information to disclose SGI–M.

The authority to determine that a document may be decontrolled may be exercised only by, or with the permission of, the individual (or office) who made the original determination. The document shall indicate the name and organization of the individual removing the document from the SGI–M category and the date of the removal. Other persons who have the document in their possession should be notified of the decontrolling of the document.

Reproduction of Matter Containing SGI–M

SGI–M may be reproduced to the minimum extent necessary consistent with need without permission of the originator. Newer digital copiers which scan and retain images of documents represent a potential security concern. If the copier is retaining SGI–M information in memory, the copier cannot be connected to a network. It should also be placed in a location that is cleared and controlled for the authorized processing of SGI–M information. Different copiers have different capabilities, including some which come with features that allow the memory to be erased. Each copier would have to be examined from a physical security perspective.

Use of Automatic Data Processing (ADP) Systems

SGI–M may be processed or produced on an ADP system provided that the system is assigned to the licensee's or contractor's facility and requires the use of an entry code/password for access to stored information. Licensees are encouraged to process this information in a computing environment that has adequate computer security controls in place to prevent unauthorized access to the information. An ADP system is defined here as a data processing system having the capability of long term storage of SGI–M. Word processors such as typewriters are not subject to the requirements as long as they do not transmit information off-site. (Note: if SGI–M is produced on a typewriter, the ribbon must be removed and stored in the same manner as other SGI–M information or media.) The basic objective of these restrictions is to prevent access and retrieval of stored SGI–M by unauthorized individuals, particularly from remote terminals. Specific files containing SGI–M will be password protected to preclude access by an unauthorized individual. The National Institute of Standards and Technology (NIST) maintains a listing of all validated encryption systems at *http://csrc.nist.gov/cryptval/140-1/1401val.htm.* SGI–M files may be transmitted over a network if the file is encrypted. In such cases, the licensee will select a commercially available encryption system that NIST has validated as conforming to Federal Information Processing Standards (FIPS). SGI–M files shall be properly labeled as ''Safeguards Information—Modified Handling'' and saved to removable media and stored in a locked file drawer or cabinet.

Telecommunications

SGI–M may not be transmitted by unprotected telecommunications circuits except under emergency or extraordinary conditions. For the purpose of this requirement, emergency or extraordinary conditions are defined as any circumstances that require immediate communications in order to report, summon assistance for, or respond to a security event (or an event that has potential security significance).

This restriction applies to telephone, telegraph, teletype, facsimile circuits, and to radio. Routine telephone or radio transmission between site security personnel, or between the site and local police, should be limited to message formats or codes that do not disclose facility security features or response procedures. Similarly, call-ins during transport should not disclose information useful to a potential adversary. Infrequent or non-repetitive telephone conversations regarding a physical security plan or program are permitted provided that the discussion is general in nature.

Individuals should use care when discussing SGI–M at meetings or in the presence of others to ensure that the conversation is not overheard by persons not authorized access. Transcripts, tapes or minutes of meetings or hearings that contain SGI–M shall be marked and protected in accordance with these requirements.

Destruction

Documents containing SGI–M should be destroyed when no longer needed. They may be destroyed by tearing into small pieces, burning, shredding or any other method that precludes reconstruction by means available to the public at large. Piece sizes one half inch or smaller composed of several pages or documents and thoroughly mixed would be considered completely destroyed.

Attachment 3: Trustworthy and Reliability Requirements for Individuals Handling Safeguards Information.

In order to ensure the safe handling, use, and control of information designated as Safeguards Information, each licensee shall control and limit access to the information to only those individuals who have established the need-to-know the information, and are considered to be trustworthy and reliable. Licensees shall document the basis for concluding that there is reasonable assurance that individuals granted access to Safeguards Information are trustworthy and reliable, and do not constitute an unreasonable risk for malevolent use of the information.

The Licensee shall comply with the requirements of this attachment:

8. The trustworthiness and reliability of an individual shall be determined based on a background investigation:

(a) The background investigation shall address at least the past 3 years, and, at a minimum, include verification of employment, education, and personal references. The licensee shall also, to the extent possible, obtain independent information to corroborate that provided

by the employee (i.e., seeking references not supplied by the individual).

(b) If an individual's employment has been less than the required 3-year period, educational references may be used in lieu of employment history.

The licensee's background investigation requirements may be satisfied for an individual that has an active Federal security clearance.

9. The licensee shall retain documentation regarding the trustworthiness and reliability of individual employees for 3 years after the individual's employment ends.

[FR Doc. E7–4753 Filed 3–14–07; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

Notice of Availability of Model Application Concerning Technical Specification Improvement Regarding Deletion of E Bar Definition and Revision to Reactor Coolant System Specific Activity Technical Specification Using the Consolidated Line Item Improvement Process

AGENCY: Nuclear Regulatory Commission.

ACTION: Notice of Availability.

SUMMARY: Notice is hereby given that the staff of the U. S. Nuclear Regulatory Commission (NRC) has prepared a model license amendment request (LAR), model safety evaluation (SE), and model proposed no significant hazards consideration (NSHC) determination related to deletion of the E Bar definition and revision to reactor coolant system (RCS) specific activity technical specification. This request revises the RCS specific activity specification for pressurized water reactors to utilize a new indicator, Dose Equivalent Xenon-133 instead of the current indicator known as E Bar.

The purpose of these models is to permit the NRC staff to efficiently process amendments to incorporate these changes into plant-specific technical specifications (TS) for Babcock and Wilcox, Westinghouse, and Combustion Engineering pressurized water reactors (PWRs). Licensees of nuclear power reactors to which the models apply can request amendments conforming to the models. In such a request, a licensee should confirm the applicability of the model LAR, model SE and NSHC determination to its plant.

DATES: The NRC staff issued a **Federal Register** Notice (71 FR 67170, November 20, 2006) which provided a model LAR, model SE, and model NSHC related to deletion of E Bar definition and revision to RCS specific activity technical specification; similarly the NRC staff herein provides a revised model LAR, a revised model SE, and a revised model NSHC. The NRC staff can most efficiently consider applications based upon the model LAR, which references the model SE, if the application is submitted within one year of this **Federal Register** Notice.

FOR FURTHER INFORMATION CONTACT: Trent Wertz, Mail Stop: O–12H2, Division of Inspection and Regional Support, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, telephone (301) 415–1568.

SUPPLEMENTARY INFORMATION:

Background

Regulatory Issue Summary 2000–06, ''Consolidated Line Item Improvement Process (CLIIP) for Adopting Standard Technical Specifications Changes for Power Reactors,'' was issued on March 20, 2000. The CLIIP is intended to improve the efficiency and transparency of NRC licensing processes. This is accomplished by processing proposed changes to the Standard Technical Specifications (STS) in a manner that supports subsequent license amendment applications. The CLIIP includes an opportunity for the public to comment on proposed changes to the STS following a preliminary assessment by the NRC staff and finding that the change will likely be offered for adoption by licensees. The CLIIP directs the NRC staff to evaluate any comments received for a proposed change to the STS and to either reconsider the change or proceed with announcing the availability of the change for proposed adoption by licensees. Those licensees opting to apply for the subject change to TSs are responsible for reviewing the NRC staff's evaluation, referencing the applicable technical justifications, and providing any necessary plant-specific information. Each amendment application made in response to the notice of availability will be processed and noticed in accordance with applicable NRC rules and procedures.

This notice involves replacement of the current PWR TS 3.4.16 limit on RCS gross specific activity with a new limit on RCS noble gas specific activity. The noble gas specific activity limit would be based on a new dose equivalent Xe-133 (DEX) definition that would replace the current E Bar average disintegration energy definition. In addition, the current dose equivalent I–131 (DEI) definition would be revised to allow the use of additional thyroid dose conversion factors (DCFs). By letter dated September 13, 2005, the Technical Specification Task Force (TSTF) proposed these changes for incorporation into the STS as TSTF–490, Revision 0, which was referenced in the **Federal Register** Notice (FRN) 71 FR 67170, of November 20, 2006, and can be viewed on the NRC's Web page at *http://www.nrc.gov/reactors/operating/licensing/techspecs.html*.

Applicability

These proposed changes will revise the definition of DOSE EQUIVALENT I–131, delete the definition of ''E Bar,'' AVERAGE DISINTEGRATION ENERGY, add a new definition for DOSE EQUIVALENT XE–133, and revise LCO 3.4.16 for Babcock and Wilcox, Westinghouse, and Combustion Engineering PWRs.

To efficiently process the incoming license amendment applications, the NRC staff requests that each licensee applying for the changes addressed by TSTF–490, Revision 0, using the CLIIP submit an LAR that adheres to the following model. Any variations from the model LAR should be explained in the licensee's submittal. Variations from the approach recommended in this notice may require additional review by the NRC staff, and may increase the time and resources needed for the review. Significant variations from the approach, or inclusion of additional changes to the license, will result in staff rejection of the submittal. Instead, licensees desiring significant variations and/or additional changes should submit a LAR that does not claim to adopt TSTF–490.

Public Notices

The staff issued a **Federal Register** Notice (71 FR 67170, November 20, 2006) that requested public comment on the NRC's pending action to delete the E Bar definition and revise the RCS specific activity technical specification. In particular, following an assessment and draft safety evaluation by the NRC staff, the staff sought public comment on proposed changes to the STS, designated TSTF–490 Revision 0. The TSTF–490 Revision 0 can be viewed on the NRC's Web page at *http://www.nrc.gov/reactors/operating/licensing/techspecs.html*. TSTF–490 Revision 0 may be examined, and/or copied for a fee, at the NRC Public Document Room, located at One White Flint North, 11555 Rockville Pike (first floor), Rockville, Maryland. Publicly available records are accessible electronically from the ADAMS Public Library component on the NRC Web site, (the Electronic Reading Room) at

http://www.nrc.gov/reading-rm/adams.html.

In response to the notice soliciting comments from the interested members of the public about NRC's pending action to delete the E Bar definition and revise the RCS specific activity technical specification, the staff received four sets of comments (from licensees and the TSTF Owners Groups, representing the licensees). Specific comments on the model SE, model LAR, and the model NSHC were offered, and are summarized and discussed below:

1. *Comment:* In Sections 3.1.4 and 3.1.7 the model safety evaluation states: ''In MODES 5 and 6, the steam generators are not used for decay heat removal, the RCS and steam generators are depressurized, and primary to secondary leakage is minimal.'' However, using the Westinghouse Standard Technical Specifications as an example, NUREG–1431, Vol. 2, Rev. 3.0, Bases 3.4.7 (RCS Loops-Mode 5, Loops Filled) states ''In MODE 5 with the RCS loops filled, the primary function of the reactor coolant is the removal of decay heat and transfer this heat either to the steam generator(SG) secondary side coolant via natural circulation (Ref. 1) or the component cooling water via the residual heat removal (RHR) heat exchangers.'' Therefore, the steam generators are taken credit for as a means of removing decay heat during MODE 5. Additionally, the RCS may be pressurized during MODE 5. The statement as written in the model safety evaluation may prevent licensees from stating that their application is consistent with the model technical evaluation.

Response: The comment addresses the MODES for which the LCO would be applicable. The NRC staff agrees that the statement in sections 3.1.4 and 3.1.7 does not acknowledge the condition of MODE 5 with the RCS loops filled. The Model SE will be modified to account for this condition.

2. *Comment:* There is currently one Technical Specification (TS) 3.4.16 limit on RCS gross specific activity, not ''limits''. The single limit is 100/E Bar in all 3 affected STS NUREGs. There are two places that refer to limits (plural).

Response: This editorial comment is correct, and the Supplemental Information section and the Model LAR will be revised accordingly.

3. *Comment:* In the Model SE, Section 2.0: Correct the title of TID 14844. ''Reactor'' is singular in the title.

Response: This editorial comment is correct, and the Model SE will be revised accordingly.

4. *Comment:* In the Model SE, Section 3.1.1: The list of Dose Conversion Factor (DCF) references should be bracketed since this change will be subject to plant specific considerations. The optional DCF reference included in TSTF–490, and discussed in the traveler's justification section 3.0 (paragraph 2, lines 4–9), for alternate source term plants should be included here as follows:

''] or [Committed Dose Equivalent (CDE) or Committed Effective Dose Equivalent (CEDE) dose conversion factors from Table 2.1 of EPA Federal Guidance Report No. 11.]''

Response: The Model SE endorsed the use of DCFs from Table 2.1 of FGR–11, 1988, ''Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion.'' As stated in the model SE, it is incumbent on the licensee to ensure that the DCFs used in the determination of DEI are consistent with the DCFs used in the applicable dose consequence analyses. As such, the references for the applicable DCFs would indeed be plant specific and the model SE has been changed accordingly.

5. *Comment:* In the model SE, Section 3.1.2: All noble gas isotope lists and DCF citations should be bracketed since these changes are subject to plant specific considerations. The 2nd paragraph is missing a forward slash mark between the words ''and'' and ''or'' in the text ''by tritium and corrosion and activation products * * *''.

Response: This editorial comment is correct, and the Model SE will be corrected.

6. *Comment:* In the Model SE, Section 3.1.3: The discussion on revised Required Action A.1 should be relocated to Model SE Section 3.1.5 that discusses the changes to TS 3.4.16 condition A.

Response: The NRC staff agrees that the discussion on revised Required Action A.1 should be relocated. The Model SE will be updated to reflect the change.

7. *Comment:* In the Model SE Section 3.1.6: This section states that Condition ''C'' is replaced with a new Condition ''B''. This is only true for the B&W and CE STS NUREGs (1430 and 1432). It is not true for the Westinghouse STS NUREG–1431, and it should also be noted that the Westinghouse plants developed this traveler for submittal to the NRC. This section should state that ''TS 3.4.16 Condition B [in NUREG–1431; C in NUREG–1430 and NUREG–1432] is replaced with a new Condition B for DEX not within limits.''

Section 3.1.6 should also discuss the addition of the LCO 3.0.4.c Note to revised Required Action B.1, consistent with the Model Application, Enclosure 1, Section 2.0, item C. Suggested wording that could be used for this purpose is:

''A Note is also added to the revised Required Action B.1 that states LCO 3.0.4.c is applicable. This Note would allow entry into a Mode or other specified condition in the LCO Applicability when LCO 3.4.16 is not being met and is the same Note that is currently stated for Required Actions A.1 and A.2. The proposed Note would allow entry into the applicable Modes when the DEX is not within its limit; in other words, the plant could go up in the Modes from Mode 4 to Mode 1 (power operation) while the DEX limit is exceeded and the DEX is being restored to within its limit. This Mode change allowance is acceptable due to the significant conservatism incorporated into the DEX specific activity limit, and the ability to restore transient specific activity excursions while the plant remains at, or proceeds to, power operation.''

Response: The NRC staff agrees with the wording with this editorial comment and the Model SE will be updated to reflect the differences in the NUREGs. Also, a discussion concerning the LCO 3.0.4.c note to required Action B.1 will be added to the Model SE Section 3.1.6.

8. *Comment:* In the Model SE, Section 3.1.8: This section incorrectly states that revised SR 3.4.16.1 has a new LCO 3.0.4.c Note. It should state that SR 3.4.16.1 has a new performance modifying Note that reads: ''Only required to be performed in Mode 1.'' The application of this style of Note is discussed in Example 1.4–5 in the latest revision of the STS NUREGs. The LCO 3.0.4.c Note addition applies only to revised Required Action B.1

Response: The NRC staff believes that the new Note for SR 3.4.16.1 is consistent with Example 1.4–5 and the Note in SR 3.4.16.2 and therefore does not need to be changed.

9. *Comment:* In the Model SE, Section 3.1.2 states ''The determination of DOSE EQUIVALENT XE–133 shall be performed using effective dose conversion factors for air submersion listed in Table III.1 of EPA Federal Guidance Report No. 12 or the average gamma disintegration energies as provided in ICRP Publication 38, ''Radionuclide Transformations'' or similar source.'' What exactly is ''similar source''? Does ''similar source'' apply to average gamma energies or to the DCFs such as published in Reg. Guide 1.109?

Response: The selection of the dose conversion factors used in the definition of DEX should be consistent with the dose conversion factors currently employed in the licensee's dose consequence analyses and as such the

reference for the dose conversion factors or the source of the gamma energies used in the definition will be site specific. Brackets will be placed around the references to indicate where site specific information should be included.

10. *Comment:* In the Model SE, Section 3.1.2 states ''* * * the calculation of DEX is based on the acute dose to the whole body and considers the noble gases KR–85M, KR–87, KR–88, XE–133M, XE–133, XE–135M, XE–135 and XE–133 * * *''. Under the same Section two additional nuclides are added to the new definition for E-AVERAGE DISINTEGRATION ENERGY; Kr-85 and XE–131M. The addition of the additional nuclides appears to conflict with the preceding technical Evaluation. Is it the expectation that these two nuclides be added to the DEX calculation in addition to those listed in the preceding section?

Response: The selection of the isotopes used in the definition of DEX will be site specific and based on the dose significant noble gas isotopes identified in the appropriate DBA dose consequence analyses. The list of noble gas isotopes will be placed in brackets to indicate that the actual list will be site specific.

11. *Comment:* The title of TSTF–490 is not capitalized consistently and is not consistent with the submitted Traveler. The title of TSTF–490 is ''Deletion of E Bar Definition and Revision to RCS Specific Activity Tech Spec.'' Note that there is no hyphen used in the term ''E Bar.''

Response: This editorial comment is correct, and the Model SE will be corrected.

12. *Comment:* In the proposed NSHC, to be consistent with 10 CFR 50.92(c)(2), the title of Criterion 2 should be revised to add the word ''Accident'' before ''Previously Evaluated.'' Specifically, it should state, ''The Proposed Change Does Not Create the Possibility of a New or Different Kind of Accident from any Accident Previously Evaluated.''

Response: This editorial comment is correct, and the proposed NSHC will be corrected.

13. *Comment:* In the Model LAR it states, ''I declare under penalty of perjury under the laws of the United States of America that I am authorized by [LICENSEE] to make this request and that the foregoing is true and correct.'' This statement is not consistent with the recommended statement given in RIS 2001–18, ''Requirements for Oath and Affirmation.'' RIS 2001–18 recommends the statement, ''I declare [or certify, verify, state] under penalty of perjury that the foregoing is true and correct.'' Note that RIS 2001–18 states that this statement must be used verbatim. We recommend that the Model Application be revised to be consistent with RIS 2001–18.

Response: The statement in the Model LAR is consistent with RIS 2001–18. The purpose of RIS 2001–18 was to inform licensees that there is an alternative to the oath or affirmation statement contained in 28 U.S.C. 1746. Both are considered acceptable. The NRC staff includes only the first option listed in 28 U.S.C. 1746 for brevity.

14. *Comment:* In the Model LAR , Section 8.0 the second reference should be numbered. Note that Section 4.0 refers to References 1 and 2.

Response: The references in Section 8.0 are numbered, however, for clarification, the Notice for Comment and the Notice for Availability will be listed as separate references.

Dated at Rockville, Maryland this 8th day of March, 2007.

For the Nuclear Regulatory Commission.

Timothy J. Kobetz,

Chief, Technical Specifications Branch, Division of Inspection and Regional Support, Office of Nuclear Reactor Regulation.

FOR INCLUSION ON THE TECHNICAL SPECIFICATION WEB PAGE THE FOLLOWING EXAMPLE OF AN APPLICATION WAS PREPARED BY THE NRC STAFF TO FACILITATE THE ADOPTION OF TECHNICAL SPECIFICATION TASK FORCE (TSTF) TRAVELER TSTF–490, REVISION 0 ''DELETION OF E BAR DEFINITION AND REVISION TO RCS SPECIFIC ACTIVITY TECH SPEC.'' THE MODEL PROVIDES THE EXPECTED LEVEL OF DETAIL AND CONTENT FOR AN APPLICATION TO ADOPT TSTF–490, REVISION 0. LICENSEES REMAIN RESPONSIBLE FOR ENSURING THAT THEIR ACTUAL APPLICATION FULFILLS THEIR ADMINISTRATIVE REQUIREMENTS AS WELL AS NRC REGULATIONS.

U. S. Nuclear Regulatory Commission, Document Control Desk, Washington, DC 20555.

Subject: Plant name, Docket N. 50-[xxx,] Re application for technical specification improvement to adopt tstf-490, revision 0, ''deletion of E bar definition and revision to RCS specific activity tech spec.''

Dear Sir or Madam:

In accordance with the provisions of Section 50.90 of Title 10 of the Code of Federal Regulations (10 CFR), [LICENSEE] is submitting a request for an amendment to the technical specifications (TS) for [PLANT NAME, UNIT NOS.]. The proposed changes would replace the current pressurized water reactor (PWR) Technical Specification (TS) 3.4.16 limit on reactor coolant system (RCS) gross specific activity with a new limit on RCS noble gas specific activity. The noble gas specific activity limit would be based on a new dose equivalent Xe-133 (DEX) definition that would replace the current E Bar average disintegration energy definition. In addition, the current dose equivalent I–131 (DEI) definition would be revised to allow the use of additional thyroid dose conversion factors (DCFs).

The changes are consistent with NRC-approved Industry Technical Specification Task Force (TSTF) Standard Technical Specification Change Traveler, TSTF–490, Revision 0, ''Deletion of E Bar Definition and Revision to RCS Specific Activity Tech Spec.'' The availability of this TS improvement was announced in the **Federal Register** on [DATE] ([ ]FR[ ]) as part of the consolidated line item improvement process (CLIIP).

Enclosure 1 provides a description and assessment of the proposed changes, as well as confirmation of applicability. Enclosure 2 provides the existing TS pages and TS Bases marked-up to show the proposed changes. Enclosure 3 provides final TS pages and TS Bases pages.

[LICENSEE] requests approval of the proposed license amendment by [DATE], with the amendment being implemented [BY DATE OR WITHIN X DAYS]. In accordance with 10 CFR 50.91, a copy of this application, with enclosures, is being provided to the designated [STATE] Official.

I declare under penalty of perjury under the laws of the United States of America that I am authorized by [LICENSEE] to make this request and that the foregoing is true and correct. [Note that request may be notarized in lieu of using this oath or affirmation statement]. If you should have any questions regarding this submittal, please contact [ ].

Sincerely,

Name, Title

Enclosures:

1. Description and Assessment of Proposed Changes
2. Proposed Technical Specification Changes and Technical Specification Bases Changes
3. Final Technical Specification and Bases pages

cc: NRR Project Manager
Regional Office
Resident Inspector
State Contact
ITSB Branch Chief

1.0 Description

This letter is a request to amend Operating License(s) [LICENSE NUMBER(S)] for [PLANT/UNIT NAME(S)].

The proposed changes would replace the current limits on primary coolant gross specific activity with limits on primary coolant noble gas activity. The noble gas activity would be based on DOSE EQUIVALENT XE–133 and would take into account only the noble gas activity in the primary coolant. The changes were approved by the NRC staff Safety Evaluation (SE) dated September 27, 2006 (ADAMS ML062700612) (Reference 1). Technical Specification Task Force (TSTF) change traveler TSTF–490, Revision 0, ''Deletion of E Bar Definition and Revision to RCS Specific Activity Tech Spec'' was announced for availability in the **Federal Register** on [DATE] as part of the

consolidated line item improvement process (CLIIP).

2.0 Proposed Changes

Consistent with NRC-approved TSTF–490, Revision 0, the proposed TS changes:

- Revise the definition of DOSE EQUIVALENT I–131.
- Delete the definition of ''E Bar, AVERAGE DISINTEGRATION ENERGY.''
- Add a new TS definition for DOSE EQUIVALENT XE–133.
- Revise LCO 3.4.16, ''RCS Specific Activity'' to delete references to gross specific activity; add limits for DOSE EQUIVALENT I–131 and DOSE EQUIVALENT XE–133; and delete Figure 3.4.16–1, ''Reactor Coolant DOSE EQUIVALENT I–131 Specific Activity Limit versus Percent of RATED THERMAL POWER.''
- Revise LCO 3.4.16 ''Applicability'' to specify the LCO is applicable in MODES 1, 2, 3, and 4.
- Modify ACTIONS Table as follows:

A. Condition A is modified to delete the reference to Figure 3.4.16–1, and define an upper limit that is applicable at all power levels.

B. NUREG–1430 and NUREG–1432 ACTIONS are reordered, moving Condition C to Condition B to be consistent with the Writer's Guide.

C. Condition B (was Condition C in NUREG–1430 and NUREG 1432) is modified to provide a Condition and Required Action for DOSE EQUIVALENT XE–133 instead of gross specific activity. The Completion Time is changed from 6 hours to 48 hours. A Note allowing the applicability of LCO 3.0.4.c is added, consistent with the Note to Required Action A.1.

D. Condition C (was Condition B in NUREG–1430 and NUREG–1432) is modified based on the changes to Conditions A and B and to reflect the change in the LCO Applicability.

Revise SR 3.4.16.1 to verify the limit for DOSE EQUIVALENT XE–133. A Note is added, consistent with SR 3.4.16.2 to allow entry into MODES 2, 3, and 4 prior to performance of the SR.

Delete SR 3.4.16.3.

3.0 Background

The background for this application is as stated in the model SE in NRC's Notice of Availability published on [DATE]([ ] FR [ ]), the NRC Notice for Comment published on [DATE] ([ ] FR [ ]), and TSTF–490, Revision 0.

4.0 Technical Analysis

[LICENSEE] has reviewed References 1, 2 and 3, and the model SE published on [DATE] ([ ]FR [ ]) as part of the CLIIP Notice for Comment. [LICENSEE] has applied the methodology in Reference 1 to develop the proposed TS changes. [LICENSEE] has also concluded that the justifications presented in TSTF–490, Revision 0 and the model SE prepared by the NRC staff are applicable to [PLANT, UNIT NOS.], and justify this amendment for the incorporation of the changes to the [PLANT] TS.

5.0 Regulatory Analysis

A description of this proposed change and its relationship to applicable regulatory requirements and guidance was provided in the NRC Notice of Availability published on [DATE] ([ ] FR [ ]), the NRC Notice for Comment published on [DATE] ([ ] FR [ ]), and TSTF–490, Revision 0.

6.0 No Significant Hazards Consideration

[LICENSEE] has reviewed the proposed no significant hazards consideration determination published in the **Federal Register** on [DATE] ([ ] FR [ ]) as part of the CLIIP. [LICENSEE] has concluded that the proposed determination presented in the notice is applicable to [PLANT] and the determination is hereby incorporated by reference to satisfy the requirements of 10 CFR 50.91(a).

7.0 Environmental Evaluation

[LICENSEE] has reviewed the environmental consideration included in the model SE published in the **Federal Register** on [DATE] ([ ] FR [ ]) as part of the CLIIP. [LICENSEE] has concluded that the staff's findings presented therein are applicable to [PLANT] and the determination is hereby incorporated by reference for this application.

8.0 References

1. NRC Safety Evaluation (SE) approving TSTF–490, Revision 0 dated September 27, 2006
2. Federal Notice for Comment published on [DATE] ([ ] FR [ ])
3. Federal Notice of Availability published on [DATE] ([ ] FR [ ])

Model Safety Evaluation, U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Technical Specification Task Force TSTF–490, Revision 0, ''Deletion of E Bar Definition and Revision to RCS Specific Activity Tech Spec''.

1.0 Introduction

By letter dated [______, 20__], [LICENSEE] (the licensee) proposed changes to the technical specifications (TS) for [PLANT NAME]. The requested changes are the adoption of TSTF–490, Revision 0, ''Deletion of E Bar Definition and Revision to RCS Specific Activity Tech Spec'' for pressurized water reactor (PWR) Standard Technical Specifications (STS). By letter dated September 13, 2005, the Technical Specification Task Force (TSTF) submitted TSTF–490 for Nuclear Regulatory Commission (NRC) staff review. This TSTF involves changes to NUREG–1430, NUREG–1431, and NUREG–1432 STS Section 3.4.16 reactor coolant system (RCS) gross specific activity limits with the addition of a new limit for noble gas specific activity. The noble gas specific activity limit would be based on a new dose equivalent Xe-133 (DEX) definition that replaces the current E Bar average disintegration energy definition. In addition, the current dose equivalent I–131 (DEI) definition would be revised to allow the use of additional thyroid dose conversion factors (DCFs).

2.0 Regulatory Evaluation

The NRC staff evaluated the impact of the proposed changes as they relate to the radiological consequences of affected design basis accidents (DBAs) that use the RCS inventory as the source term. The source term assumed in radiological analyses should be based on the activity associated with the projected fuel damage or the maximum RCS technical specifications (TS) values, whichever maximizes the radiological consequences. The limits on RCS specific activity ensure that the offsite doses are appropriately limited for accidents that are based on releases from the RCS with no significant amount of fuel damage.

The Steam Generator Tube Rupture (SGTR) accident and the Main Steam Line Break (MSLB) accident typically do not result in fuel damage and therefore the radiological consequence analyses are based on the release of primary coolant activity at maximum TS limits. For accidents that result in fuel damage, the additional dose contribution from the initial activity in the RCS is not normally evaluated and is considered to be insignificant in relation to the dose resulting from the release of fission products from the damaged fuel.

For licensees that incorporate the source term as defined in Technical Information Document (TID) 14844, AEC, 1962, ''Calculation of Distance Factors for Power and Test Reactors Sites,'' in their dose consequence analyses, the NRC staff uses the regulatory guidance provided in NUREG–0800, ''Standard Review Plan (SRP) for the Review of Safety Analysis Reports for Nuclear Power Plants,'' Section 15.1.5, ''Steam System Piping Failures Inside and Outside of Containment (PWR),'' Appendix A, ''Radiological Consequences of Main Steam Line Failures Outside Containment,'' Revision 2, for the evaluation of MSLB accident analyses and NUREG–0800, SRP Section 15.6.3, ''Radiological Consequences of Steam Generator Tube Failure (PWR),'' Revision 2, for evaluating SGTR accidents analyses. In addition, the NRC staff uses the guidance from RG 1.195, ''Methods and Assumptions for Evaluating Radiological Consequences of Design Basis Accidents at Light Water Nuclear Power Reactors,'' May 2003, for those licensees that chose to use its guidance for dose consequence analyses using the TID 14844 source term.

For licensees using the alternative source term (AST) in their dose consequence analyses, the NRC staff uses the regulatory guidance provided in NUREG–0800, SRP Section 15.0.1, ''Radiological Consequence Analyses Using Alternative Source Terms,'' Revision 0, July 2000, and the methodology and assumptions stated in Regulatory Guide (RG) 1.183, ''Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors'', July 2000.

The applicable dose criteria for the evaluation of DBAs depends on the source term incorporated in the dose consequence analyses. For licensees using the TID 14844 source term, the maximum dose criteria to the whole body and the thyroid that an individual at the exclusion area boundary (EAB) can receive for the first 2 hours following an accident, and at the low

population zone (LPZ) outer boundary for the duration of the radiological release, are specified in Title 10 of the Code of Federal Regulations (10 CFR) Part 100.11. These criteria are 25 roentgen equivalent man (rem) total whole body dose and 300 rem thyroid dose from iodine exposure. The accident dose criteria in 10 CFR 100.11 is supplemented by accident specific dose acceptance criteria in SRP 15.1.5, Appendix A, SRP 15.6.3 or Table 4 of RG 1.195, ''Methods and Assumptions for Evaluating Radiological Consequences of Design Basis Accidents at Light Water Nuclear Power Reactors,'' May 2003.

For control room dose consequence analyses that use the TID 14844 source term, the regulatory requirement for which the NRC staff bases its acceptance is General Design Criterion (GDC) 19 of Appendix A to 10 CFR Part 50, ''Control Room''. GDC 19 requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident. NUREG–0800, SRP Section 6.4, ''Control Room Habitability System,'' Revision 2, July 1981, provides guidelines defining the dose equivalency of 5 rem whole body as 30 rem for both the thyroid and skin dose. For licensees adopting the guidance from RG 1.196, ''Control Room Habitability at Light Water Nuclear Power Reactors,'' May 2003, Section C.4.5 of RG 1.195, May 2003, states that in lieu of the dose equivalency guidelines from Section 6.4 of NUREG–0800, the 10 CFR 20.1201 annual organ dose limit of 50 rem can be used for both the thyroid and skin dose equivalent of 5 rem whole body.

Licensees using the AST are evaluated against the dose criteria specified in 10 CFR Part 50.67(b)(2). The off-site dose criteria are 25 rem total effective dose equivalent (TEDE) at the EAB for any 2-hour period following the onset of the postulated fission product release and 25 rem TEDE at the outer boundary of the LPZ for the duration of the postulated fission product release. In addition, 10 CFR Part 50.67(b)(2)(iii) requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem TEDE for the duration of the accident.

3.0 Technical Evaluation

3.1 Technical Evaluation of TSTF–490 TS Changes

3.1.1 Revision to the Definition of DEI

The list of acceptable DCFs for use in the determination of DEI include the following:

• [Table III of TID–14844, AEC, 1962, ''Calculation of Distance Factors for Power and Test Reactor Sites.'']

• [Table E–7 of Regulatory Guide 1.109, Revision 1, NRC, 1977.]

• [ICRP 30, 1979, page 192–212, Table titled ''Committed Dose Equivalent in Target Organs or Tissues per Intake of Unit Activity.'']

• [Committed Dose Equivalent (CDE) or Committed Effective Dose Equivalent (CEDE) dose conversion factors from Table 2.1 of EPA Federal Guidance Report No. 11.'']

• [Table 2.1 of EPA Federal Guidance Report No. 11, 1988, ''Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion.'']

Note: It is incumbent on the licensee to ensure that the DCFs used in the determination of DEI are consistent with the applicable dose consequence analyses.

3.1.2 Deletion of the Definition of E Bar and the Addition of a New Definition for DE Xe-133

The new definition for DEX is similar to the definition for DEI. The determination of DEX will be performed in a similar manner to that currently used in determining DEI, except that the calculation of DEX is based on the acute dose to the whole body and considers the noble gases [Kr-85m, Kr-85, Kr-87, Kr-88, Xe-131m, Xe-133m, Xe-133, Xe-135m, Xe-135, and Xe-138] which are significant in terms of contribution to whole body dose. Some noble gas isotopes are not included due to low concentration, short half life, or small dose conversion factor. The calculation of DEX would use either the average gamma disintegration energies for the nuclides or the effective dose conversion factors from Table III.1 of EPA FGR No. 12. Using this approach, the limit on the amount of noble gas activity in the primary coolant would not fluctuate with variations in the calculated values of E Bar. If a specified noble gas nuclide is not detected, the new definition states that it should be assumed the nuclide is present at the minimum detectable activity. This will result in a conservative calculation of DEX.

When E Bar is determined using a design basis approach in which it is assumed that 1.0% of the power is being generated by fuel rods having cladding defects and it is also assumed that there is no removal of fission gases from the letdown flow, the value of E Bar is dominated by Xe-133. The other nuclides have relatively small contributions. However, during normal plant operation there are typically only a small amount of fuel clad defects and the radioactive nuclide inventory can become dominated by tritium and corrosion and/or activation products, resulting in the determination of a value of E Bar that is very different than would be calculated using the design basis approach. Because of this difference, the accident dose analyses become disconnected from plant operation and the limiting condition for operation (LCO) becomes essentially meaningless. It also results in a TS limit that can vary during operation as different values for E Bar are determined.

This change will implement a LCO that is consistent with the whole body radiological consequence analyses which are sensitive to the noble gas activity in the primary coolant but not to other non-gaseous activity currently captured in the E Bar definition. LCO 3.4.16 specifies the limit for primary coolant gross specific activity as 100/E Bar __Ci/gm. The current E Bar definition includes radioisotopes that decay by the emission of both gamma and beta radiation. The current Condition B of LCO 3.4.16 would rarely, if ever, be entered for exceeding 100/E Bar since the calculated value is very high (the denominator is very low) if beta emitters such as tritium (H–3) are included in the determination, as required by the E Bar definition.

TS Section 1.1 definition for E—AVERAGE DISINTEGRATION ENERGY (E Bar) is deleted and replaced with a new definition for DEX which states:

''DOSE EQUIVALENT XE-133 shall be that concentration of Xe-133 (microcuries per gram) that alone would produce the same acute dose to the whole body as the combined activities of noble gas nuclides [Kr-85m, Kr-85, Kr-87, Kr-88, Xe-131m, Xe-133m, Xe-133, Xe-135m, Xe-135, and Xe-138] actually present. If a specific noble gas nuclide is not detected, it should be assumed to be present at the minimum detectable activity. The determination of DOSE EQUIVALENT XE-133 shall be performed using [effective dose conversion factors for air submersion listed in Table III.1 of EPA Federal Guidance Report No. 12, 1993, ''External Exposure to Radionuclides in Air, Water, and Soil'' or the average gamma disintegration energies as provided in ICRP Publication 38, ''Radionuclide Transformations'' or similar source.]''

The change incorporating the newly defined quantity DEX is acceptable from a radiological dose perspective since it will result in an LCO that more closely relates the non-iodine RCS activity limits to the dose consequence analyses which form their bases.

Note: It is incumbent on the licensee to ensure that the DCFs used in the determination of DEI and the newly defined DEX are consistent with the DCFs used in the applicable dose consequence analysis.

3.1.3 LCO 3.4.16, ''RCS Specific Activity''

LCO 3.4.16 is modified to specify that iodine specific activity in terms of DEI and noble gas specific activity in terms of DEX shall be within limits. Currently the limiting indicators are not explicitly identified in the LCO, but are instead defined in current Condition C and Surveillance Requirement (SR) 3.4.16.1 for gross non-iodine specific activity and in current Condition A and SR 3.4.16.2 for iodine specific activity.

The change states ''RCS DOSE EQUIVALENT 1–131 and DOSE EQUIVALENT XE–133 specific activity shall be within limits.'' NOTE: IT IS INCUMBENT ON THE LICENSEE TO ENSURE THAT THE SITE SPECIFIC LIMITS FOR BOTH DEI AND DEX ARE CONSISTENT WITH THE CURRENT SGTR AND MSLB RADIOLOGICAL CONSEQUENCE ANALYSES.

3.1.4 TS3.4.16 Applicability

TS 3.4.16 Applicability is modified to include all of MODE 3 and MODE 4. It is necessary for the LCO to apply during MODES 1 through 4 to limit the potential radiological consequences of an SGTR or MSLB that may occur during these MODES. In MODE 5 with the RCS loops filled, the steam generators are specified as a backup means of decay heat removal via natural circulation. In this mode, however, due to the

reduced temperature of the RCS, the probability of a DBA involving the release of significant quantities of RCS inventory is greatly reduced. Therefore, monitoring of RCS specific activity is not required. In MODE 5 with the RCS loops not filled and in MODE 6 the steam generators are not used for decay heat removal, the RCS and steam generators are depressurized and primary to secondary leakage is minimal. Therefore, the monitoring of RCS specific activity is not required. The change to modify the TS 3.4.16 Applicability to include all of MODE 3 and MODE 4 is necessary to limit the potential radiological consequences of an SGTR or MSLB that may occur during these MODES and is therefore acceptable from a radiological dose perspective.

3.1.5 TS3.4.16 Condition A

TS 3.4.16 Condition A is revised by replacing the DEI site specific limit ''> [1.0] _Ci/gm'' with the words ''not within limit'' to be consistent with the revised TS 3.4.16 LCO format. The site specific DEI limit of ≤ [1.0] _Ci/gm is contained in SR 3.4.16.2. This proposed format change will not alter current STS requirements and is acceptable from a radiological dose perspective.

TS 3.4.16 Required Action A.1 is revised to remove the reference to Figure 3.4.16–1 ''Reactor Coolant DOSE EQUIVALENT I–131 Specific Activity Limit versus Percent of RATED THERMAL POWER'' and insert a limit of less than or equal to the site specific DEI spiking limit. The curve contained in Figure 3.4.16–1 was provided by the AEC in a June 12, 1974 letter from the AEC on the subject, ''Proposed Standard Technical Specifications for Primary Coolant Activity.'' Radiological dose consequence analyses for SGTR and MSLB accidents that take into account the pre-accident iodine spike do not consider the elevated RCS iodine specific activities permitted by Figure 3.4.16–1 for operation at power levels below 80% RTP. Instead, the pre-accident iodine spike analyses assume a DEI concentration [60] times higher than the corresponding long term equilibrium value, which corresponds to the specific activity limit associated with 100% RTP operation. It is acceptable that TS 3.4.16 Required Action A.1 should be based on the short term site specific DEI spiking limit to be consistent with the assumptions contained in the radiological consequence analyses.

3.1.6 TS3.4.16 Condition B Revision To Include Action for DEX Limit

TS 3.4.16 Condition C is replaced with a new Condition B [in NUREG–1431; C in NUREG–1430 and NUREG–1432] for DEX not within limits. This change is made to be consistent with the change to the TS 3.4.16 LCO, which requires the DEX specific activity to be within limits as discussed above in Section 3.1.3. The DEX limit is site specific and the numerical value in units of _Ci/gm is contained in revised SR 3.4.16.1. The site specific limit of DEX in _Ci/gm is established based on the maximum accident analysis RCS activity corresponding to 1% fuel clad defects with sufficient margin to accommodate the exclusion of those isotopes based on low concentration, short half life, or small dose conversion factors. The primary purpose of the TS 3.4.16 LCO on RCS specific activity and its associated Conditions is to support the dose analyses for DBAs. The whole body dose is primarily dependent on the noble gas activity, not the non-gaseous activity currently captured in the E Bar definition.

The Completion Time for revised TS 3.4.16 Required Action B.1 will require restoration of DEX to within limit in 48 hours. This is consistent with the Completion Time for current Required Action A.2 for DEI. The radiological consequences for the SGTR and the MSLB accidents demonstrate that the calculated thyroid doses are generally a greater percentage of the applicable acceptance criteria than the calculated whole body doses. It then follows that the Completion Time for noble gas activity being out of specification in the revised Required Action B.1 should be at least as great as the Completion Time for iodine specific activity being out of specification in current Required Action A.2. Therefore the Completion Time of 48 hours for revised Required Action B.1 is acceptable from a radiological dose perspective. A Note is also added to the revised Required Action B.1 that states LCO 3.0.4.c is applicable. This Note would allow entry into a Mode or other specified condition in the LCO Applicability when LCO 3.4.16 is not being met and is the same Note that is currently stated for Required Actions A.1 and A.2. The proposed Note would allow entry into the applicable Modes from MODE 4 to MODE 1 (power operation) while the DEX limit is exceeded and the DEX is being restored to within its limit. This Mode change is acceptable due to the significant conservatism incorporated into the DEX specific activity limit, the low probability of an event occurring which is limiting due to exceeding the DEX specific activity limit, and the ability to restore transient specific excursions while the plant remains at, or proceeds to power operation.

3.1.7 TS 3.4.16 Condition C

TS 3.4.16 Condition C is revised to include Condition B (DEX not within limit) if the Required Action and associated Completion Time of Condition B is not met. This is consistent with the changes made to Condition B which now provide the same completion time for both components of RCS specific activity as discussed in the revision to Condition B. The revision to Condition C also replaces the limit on DEI from the deleted Figure 3.4.16–1, with a site specific value of > [60] _Ci/gm. This change makes Condition C consistent with the changes made to TS 3.4.16 Required Action A.1.

The change to TS 3.4.16 Required Action C.1 requires the plant to be in MODE 3 within 6 hours and adds a new Required Action C.2, which requires the plant to be in MODE 5 within 36 hours. These changes are consistent with the changes made to the TS 3.4.16 Applicability. The revised LCO is applicable throughout all of MODES 1 through 4 to limit the potential radiological consequences of an SGTR or MSLB that may occur during these MODES. In MODE 5 with the RCS loops filled, the steam generators are specified as a backup means of decay heat removal via natural circulation. In this mode, however, due to the reduced temperature of the RCS, the probability of a DBA involving the release of significant quantities of RCS inventory is greatly reduced. Therefore, monitoring of RCS specific activity is not required. In MODE 5 with the RCS loops not filled and MODE 6, the steam generators are not used for decay heat removal, the RCS and steam generators are depressurized, and primary to secondary leakage is minimal. Therefore, the monitoring of RCS specific activity is not required.

A new TS 3.4.16 Required Action C.2 Completion Time of 36 hours is added for the plant to reach MODE 5. This Completion Time is reasonable, based on operating experience, to reach MODE 5 from full power conditions in an orderly manner and without challenging plant systems and the value of 36 hours is consistent with other TS which have a Completion Time to reach MODE 5.

3.1.8 SR3.4.16.1 DEX Surveillance

The change replaces the current SR 3.4.16.1 surveillance for RCS gross specific activity with a surveillance to verify that the site specific reactor coolant DEX specific activity is ≤ [X] _Ci/gm. This change provides a surveillance for the new LCO limit added to TS 3.4.16 for DEX. The revised SR 3.4.16.1 surveillance requires performing a gamma isotopic analysis as a measure of the noble gas specific activity of the reactor coolant at least once every 7 days, which is the same frequency required under the current SR 3.4.16.1 surveillance for RCS gross non-iodine specific activity. The surveillance provides an indication of any increase in the noble gas specific activity. The results of the surveillance on DEX allow proper remedial action to be taken before reaching the LCO limit under normal operating conditions.

SR 3.4.16.1 is modified by inclusion of a NOTE which permits the use of the provisions of LCO 3.0.4.c. This allowance permits entry into the applicable MODE(S) while relying on the ACTIONS. This allowance is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient specific activity excursions while the plant remains at, or proceeds to power operation. This allows entry into MODE 4, MODE 3, and MODE 2 prior to performing the surveillance. This allows the surveillance to be performed in any of those MODES, prior to entering MODE 1, similar to the current surveillance SR 3.4.16.2 for DEI.

3.1.9 SR3.4.16.3 Deletion

The current SR 3.4.16.3, which required the determination of E Bar, is deleted. TS 3.4.16 LCO on RCS specific activity supports the dose analyses for DBAs, in which the whole body dose is primarily dependent on the noble gas concentration, not the non-gaseous activity currently captured in the E Bar definition. With the elimination of the limit for RCS gross specific activity and the addition of the new LCO limit for noble gas specific activity, this SR to determine E Bar is no longer required.

3.2 Precedent

The technical specifications developed for the Westinghouse AP600 and AP1000

advanced reactor designs incorporate an LCO for RCS DEX activity in place of the LCO on non-iodine gross specific activity based on E Bar. This approach was approved by the NRC staff for the AP600 in NUREG–1512, ''Final Safety Evaluation Report Related to the Certification of the AP600 Standard Design, Docket No. 52–003,'' dated August 1998 and for the AP1000 in the NRC letter to Westinghouse Electric Company dated September 13, 2004. In addition, the curve describing the maximum allowable iodine concentration during the 48-hour period of elevated activity as a function of power level, was not included in the TS approved for the AP600 and API000 advanced reactor designs.

4.0 State Consultation

In accordance with the Commission's regulations, the [___] State official was notified of the proposed issuance of the amendment. The State official had [(1) no comments or (2) the following comments—with subsequent disposition by the staff].

5.0 Environmental Consideration

The amendment[s] change[s] a requirement with respect to the installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 or surveillance requirements. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration and there has been no public comment on such finding published [DATE] ([ ] FR [ ]). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

6.0 Conclusion

The Commission has concluded, based on the considerations discussed above, that (1) There is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

Proposed No Significant Hazards Consideration Determination

Description of Amendment Request: [LICENSEE] requests adoption of an approved change to the Standard Technical Specifications (STS) for pressurized water reactor (PWR) plants (NUREG–1430, NUREG–1431, & NUREG–1432) and plant specific technical specifications (TS), to replace the current limits on primary coolant gross specific activity with limits on primary coolant noble gas activity. The noble gas activity would be based on DOSE EQUIVALENT XE–133 and would take into account only the noble gas activity in the primary coolant. The changes are consistent with NRC-approved Industry/Technical Specification Task Force (TSTF) Standard Technical Specification Change Traveler, TSTF–490, Revision 0.

Basis for proposed no-significant-hazards-consideration determination: As required by 10 CFR 50.91(a), an analysis of the issue of no-significant-hazards-consideration is presented below:

Criterion 1–The Proposed Change Does Not Involve a Significant Increase in the Probability or Consequences of an Accident Previously Evaluated

Reactor coolant specific activity is not an initiator for any accident previously evaluated. The Completion Time when primary coolant gross activity is not within limit is not an initiator for any accident previously evaluated. The current variable limit on primary coolant iodine concentration is not an initiator to any accident previously evaluated. As a result, the proposed change does not significantly increase the probability of an accident. The proposed change will limit primary coolant noble gases to concentrations consistent with the accident analyses. The proposed change to the Completion Time has no impact on the consequences of any design basis accident since the consequences of an accident during the extended Completion Time are the same as the consequences of an accident during the Completion Time. As a result, the consequences of any accident previously evaluated are not significantly increased.

Criterion 2—The Proposed Change Does Not Create the Possibility of a New or Different Kind of Accident From any Accident Previously Evaluated

The proposed change in specific activity limits does not alter any physical part of the plant nor does it affect any plant operating parameter. The change does not create the potential for a new or different kind of accident from any previously calculated.

Criterion 3—The Proposed Change Does Not Involve a Significant Reduction in the Margin of Safety

The proposed change revises the limits on noble gase radioactivity in the primary coolant. The proposed change is consistent with the assumptions in the safety analyses and will ensure the monitored values protect the initial assumptions in the safety analyses.

Based upon the reasoning presented above and the previous discussion of the amendment request, the requested change does not involve a significant hazards consideration.

Dated at Rockville, Maryland this _ day of ___, XXXX.

For The Nuclear Regulatory Commission.

Project Manager,
Plant Licensing Branch [ ],
Division of Operating Reactor Licensing,
Office of Nuclear Reactor Regulation.

[FR Doc. E7–4754 Filed 3–14–07; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

Notice of Opportunity To Comment on Model Safety Evaluation and Model License Amendment Request on Technical Specification Improvement Regarding Relocation of Departure From Nucleate Boiling Parameters to the Core Operating Limits Report for Combustion Engineering Pressurized Water Reactors Using the Consolidated Line Item Improvement Process

AGENCY: Nuclear Regulatory Commission.

ACTION: Request for comment.

SUMMARY: Notice is hereby given that the staff of the U. S. Nuclear Regulatory Commission (NRC) has prepared a model license amendment request (LAR), model safety evaluation (SE), and model proposed no significant hazards consideration (NSHC) determination related to changes to Standard Technical Specifications (STSs) for Combustion Engineering Pressurized Water Reactors (PWRs), NUREG–1432, Revision 3.1. This change would allow the numerical limits located in technical specification (TS) 3.4.1, ''RCS Pressure, Temperature, and Flow [Departure from Nucleate Boiling (DNB)] Limits'' to be replaced with references to the Core Operating Limits Report (COLR). Associated changes are also included for the TS 3.4.1 Bases, and TS 5.6.3 ''Core Operating Limits Report (COLR).'' The Technical Specifications Task Force (TSTF) proposed these changes to the TS in TSTF–487 Revision 0, ''Relocate DNB Parameters to the COLR.''

The purpose of the model SE, LAR, and NSHC is to permit the NRC to efficiently process amendments to incorporate these changes into plant-specific TSs for Combustion Engineering PWRs. Licensees of nuclear power reactors to which the models apply can request amendments conforming to the models. In such a request, a licensee should confirm the applicability of the model LAR, model SE and NSHC determination to its plant. The NRC staff is requesting comments on the model LAR, model SE and NSHC determination before announcing their availability for referencing in license amendment applications.

DATES: The comment period expires 30 days from the date of this publication. Comments received after this date will be considered if it is practical to do so, but the Commission is able to ensure consideration only for comments received on or before this date.

ADDRESSES: Comments may be submitted either electronically or via U.S. mail.

Submit written comments to: Chief, Rulemaking, Directives, and Editing Branch, Division of Administrative Services, Office of Administration, *Mail Stop:* T–6 D59, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001. *Hand deliver comments to:* 11545 Rockville Pike, Rockville, Maryland 20852, between 7:45 a.m. and 4:15 p.m. on Federal workdays. Submit comments by electronic mail to: *CLIIP@nrc.gov*.

Copies of comments received may be examined at the NRC's Public Document Room, One White Flint North, Public File Area O1–F21, 11555 Rockville Pike (first floor), Rockville, Maryland.

FOR FURTHER INFORMATION CONTACT: Ross Telson, *Mail Stop:* O–12H2, Division of Inspection and Regional Support, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, telephone (301) 415–2256.

SUPPLEMENTARY INFORMATION:

Background

Regulatory Issue Summary 2000–06, ''Consolidated Line Item Improvement Process [CLIIP] for STSs Changes for Power Reactors,'' was issued on March 20, 2000. The CLIIP is intended to improve the efficiency and transparency of NRC licensing processes. This is accomplished by processing proposed changes to the TS in a manner that supports subsequent license amendment applications. The CLIIP includes an opportunity for the public to comment on proposed changes to the TS following a preliminary assessment by the NRC staff and finding that the change will likely be offered for adoption by licensees. At the conclusion of the notice for comment period the NRC staff will evaluate any comments received for the proposed TS change and either reconsider the change or proceed with announcing the availability of the change for proposed adoption by licensees. Those licensees opting to apply for the subject change to TSs are responsible for reviewing the NRC staff's evaluation, referencing the applicable technical justifications, and providing any necessary plant-specific information. Following the public comment period, the model LAR and model SE will be finalized, and posted on the NRC web page. Each amendment application made in response to the notice of availability will be processed and noticed in accordance with applicable NRC rules and procedures.

This notice involves the replacement of the departure from nucleate boiling (DNB) parameter limits in TS 3.4.1 with references to the defined formal COLR for the values of these limits. With this alternative, reload license amendments for the sole purpose of updating the cycle specific DNB parameter limits will be unnecessary. This change would allow licensees of Combustion Engineering PWRs to recalculate DNB parameter limits in the COLR using NRC-approved methodologies. By letter dated June 20, 2005, the TSTF proposed these changes for incorporation into the STSs as TSTF–487, Revision 0. These changes are based on the NRC Generic Letter 88–16 ''Removal of Cycle-Specific Parameter Limits from Technical Specifications.'' This document is accessible electronically from the Agency-wide Documents Access and Management System's (ADAMS) Public Electronic Reading Room on the Internet (ADAMS Accession No. ML041830597) at the NRC Web site *http://www.nrc.gov/reading-rm/adams.html.* Persons who do not have access to ADAMS or who encounter problems in accessing the documents located in ADAMS should contact the NRC Public Document Room Reference staff by telephone at 1–800–397–4209, 301–415–4737, or by e-mail to *pdr@nrc.gov.*

Applicability

These proposed changes will revise LCO 3.4.1, SR 3.4.1, the Bases associated with TS 3.4.1, and TS 5.6.3 for Combustion Engineering PWRs. To efficiently process the incoming license amendment applications, the NRC staff requests that each licensee applying for the changes addressed by TSTF–487 Revision 0, using the CLIIP submit an LAR that adheres to the following model. Any variations from the model LAR should be explained in the licensee's submittal. Variations from the approach recommended in this notice may require additional review by the NRC staff, and may increase the time and resources needed for the review. Significant variations from the approach, or inclusion of additional changes to the license, will result in NRC staff rejection of the submittal. Instead, licensees desiring significant variations and/or additional changes should submit a LAR that does not claim to adopt TSTF–487.

Public Notices

This notice requests comments from interested members of the public within 30 days of the date of this publication. Following the NRC staff's evaluation of comments received as a result of this notice, the NRC staff may reconsider the proposed change or may proceed with announcing the availability of the change in a subsequent notice (perhaps with some changes to the model LAR, model SE or model NSHC determination as a result of public comments). If the NRC staff announces the availability of the change, licensees wishing to adopt the change will submit an application in accordance with applicable rules and other regulatory requirements. The NRC staff will, in turn, issue for each application a notice of consideration of issuance of amendment to facility operating license(s), a proposed NSHC determination, and an opportunity for a hearing. A notice of issuance of an amendment to operating license(s) will also be issued to announce the revised requirements for each plant that applies for and receives the requested change.

Dated at Rockville, Maryland this 7th day of March, 2007.

For The Nuclear Regulatory Commission.

Timothy J. Kobetz,

Chief, Technical Specifications Branch, Division of Inspection and Regional Support, Office of Nuclear Reactor Regulation.

FOR INCLUSION ON THE TECHNICAL SPECIFICATION WEB PAGE THE FOLLOWING EXAMPLE OF AN APPLICATION WAS PREPARED BY THE NRC STAFF TO FACILITATE THE ADOPTION OF TECHNICAL SPECIFICATIONS TASK FORCE (TSTF) TRAVELER TSTF–487, REVISION 0 ''RELOCATE DNB PARAMETERS TO THE COLR.'' THE MODEL PROVIDES THE EXPECTED LEVEL OF DETAIL AND CONTENT FOR AN APPLICATION TO ADOPT TSTF–487, REVISION 0. LICENSEES REMAIN RESPONSIBLE FOR ENSURING THAT THEIR ACTUAL APPLICATION FULFILLS THEIR ADMINISTRATIVE REQUIREMENTS AS WELL AS NRC REGULATIONS.

U. S. Nuclear Regulatory Commission, Document Control Desk, Washington, DC 20555.

SUBJECT: PLANT NAME, DOCKET NO. 50–[xxx,] RE: APPLICATION FOR TECHNICAL SPECIFICATION IMPROVEMENT TO ADOPT TSTF–487, REVISION 0, ''RELOCATE DNB PARAMETERS TO THE COLR''

Dear Sir or Madam:

In accordance with the provisions of Section 50.90 of Title 10 of the Code of Federal Regulations (10 CFR), [LICENSEE] is submitting a request for an amendment to the technical specifications (TS) for [PLANT NAME, UNIT NOS.]. The proposed changes would allow [PLANT NAME] to replace the DNB numeric limits in TS with references to the core operating limits report (COLR).

The changes are consistent with NRC-approved Industry Technical Specification Task Force (TSTF) Standard Technical Specification Change Traveler, TSTF–487 Revision 0. The availability of this TS improvement was announced in the **Federal Register** on [DATE] ([ ]FR[ ]) as part of the consolidated line item improvement process (CLIIP).

Enclosure 1 provides a description and assessment of the proposed changes, as well as confirmation of applicability. Enclosure 2 provides the existing TS pages and TS Bases marked-up to show the proposed changes. Enclosure 3 provides final TS pages and TS Bases pages. [LICENSEE] requests approval of the proposed license amendment by [DATE], with the amendment being implemented [BY DATE OR WITHIN X DAYS]. In accordance with 10 CFR 50.91, a copy of this application, with enclosures, is being provided to the designated [STATE] Official.

I declare under penalty of perjury under the laws of the United States of America that I am authorized by [LICENSEE] to make this request and that the foregoing is true and correct. [Note that request may be notarized in lieu of using this oath or affirmation statement]. If you should have any questions regarding this submittal, please contact [ ].

Sincerely,

Name, Title

Enclosures:

1. Description and Assessment of Proposed Changes
2. Proposed Technical Specification Changes and Technical Specification Bases Changes
3. Final Technical Specification and Bases pages

cc: NRR Project Manager
Regional Office
Resident Inspector
State Contact
ITSB Branch Chief

1.0 DESCRIPTION

This letter is a request to amend Operating License(s) [LICENSE NUMBER(S)] for [PLANT/UNIT NAME(S)]. The proposed changes would revise Technical Specification (TS) 3.4.1, ''RCS Pressure, Temperature, and Flow [Departure from Nucleate Boiling (DNB)] Limits,'' the Bases for TS 3.4.1, and TS 5.6.3 ''Core Operating Limits Report (COLR),'' to allow [PLANT NAME] to place the DNB numeric limits with references to the COLR.

Technical Specification Task Force (TSTF) change traveler TSTF–487, Revision 0 ''Relocate DNB Parameters to the COLR'' was announced for availability in the **Federal Register** on [DATE] as part of the consolidated line item improvement process (CLIIP).

2.0 PROPOSED CHANGES

Consistent with NRC-approved TSTF–487 Revision 0, the following changes are proposed:

• Revise the limiting conditions for operation and surveillance requirements in TS 3.4.1 to replace the DNB numeric limits for reactor coolant pressure, temperature, and flow with references to limits for those parameters calculated in the COLR.

• Revise the bases associated with TS 3.4.1 to reflect that the DNB numeric limits are contained in the COLR.

• Revise TS 5.6.3 to add the methodology requirements for calculating the DNB numeric limits in the COLR,

3.0 BACKGROUND

The background for this application is as stated in the model SE in NRC's Notice of Availability published on [DATE] ([ ] FR [ ]), the NRC Notice for Comment published on [DATE] ([ ] FR [ ]), and TSTF–487, Revision 0.

4.0 TECHNICAL ANALYSIS

[LICENSEE] has reviewed Generic Letter 88–16, and the model SE published on [DATE] ([ ] FR [ ]) as part of the CLIIP Notice for Comment. [LICENSEE] has applied the methodology in Generic Letter 88–16 to develop the proposed TS changes. [LICENSEE] has also concluded that the justifications presented in TSTF–487, Revision 0 and the model SE prepared by the NRC staff are applicable to [PLANT, UNIT NOS.], and justify this amendment for the incorporation of the changes to the [PLANT] TS.

5.0 REGULATORY ANALYSIS

A description of this proposed change and its relationship to applicable regulatory requirements and guidance was provided in the NRC Notice of Availability published on [DATE] ([ ] FR [ ]), the NRC Notice for Comment published on [DATE] ([ ] FR [ ]), and TSTF–487, Revision 0.

6.0 NO SIGNIFICANT HAZARDS CONSIDERATION

[LICENSEE] has reviewed the proposed no significant hazards consideration determination published in the **Federal Register** on [DATE] ([ ] FR [ ]) as part of the CLIIP. [LICENSEE] has concluded that the proposed determination presented in the notice is applicable to [PLANT] and the determination is hereby incorporated by reference to satisfy the requirements of 10 CFR 50.91(a).

7.0 ENVIRONMENTAL EVALUATION

[LICENSEE] has reviewed the environmental consideration included in the model SE published in the **Federal Register** on [DATE] ([ ] FR [ ]) as part of the CLIIP. [LICENSEE] has concluded that the staff's findings presented therein are applicable to [PLANT] and the determination is hereby incorporated by reference for this application.

Proposed Safety Evaluation, U.S Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation.

Consolidated Line Item Improvement Technical Specification Task Force (TSTF).

Change TSTF–487, Revision 0, RELOCATE DNB PARAMETERS TO THE COLR.

1.0 INTRODUCTION

By application dated [Date], (Ref. 7.1), the [Name of Licensee] (the licensee) requested changes to the Technical Specifications (TS) for the [Name of Facility].

The proposed changes would revise TS 3.4.1, the associated bases of TS 3.4.1, and TS 5.6.3 to replace the departure from nucleate boiling (DNB) parameters limits in Technical Specifications (TSs) with references to the Core Operating Limits Report (COLR). These changes would allow the licensee to recalculate the DNB parameter limits using NRC-approved methodologies without the need for a license amendment request (LAR).

The proposed changes include the following:

• Change TS 3.4.1, ''RCS Pressure, Temperature, and Flow [Departure from Nucleate Boiling (DNB)] Limits,'' Limiting Conditions for Operation (LCO) 3.4.1 and the associated Surveillance Requirements (SRs) to replace the specific limit values of RCS pressurizer pressure, cold leg temperature, and RCS total flow rate with ''the limits specified in the COLR.''

• Change the Bases for LCO 3.4.1 to reflect that the DNB limits are specified in the COLR.

• Change Section 5.6.3 of TS, ''Core Operating Limits Report (COLR)'' to include the NRC approved methodologies and requirements used to calculate the DNB limits.

Generic Letter (GL) 88–16 titled ''Removal of Cycle-Specific Parameter Limits from Technical Specifications'' (Ref. 7.2) is the regulatory guidance for this change.

2.0 REGULATORY EVALUATION

The Commission's regulatory requirements related to the content of Technical Specifications are specified in Title 10 CFR (Code of Federal Regulations), Section 50.36, ''Technical Specifications.'' 10 CFR 50.36(c)(2)(i) defines that limiting conditions for operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility. For the DNB parameters, 10 CFR 50.36(c)(2)(ii)(B) Criterion 2 applies, which requires that TS LCOs be established for each process variable, design feature, or operating restriction that is an initial condition of a design basis accident or transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

LARs are required for each fuel cycle design that results in changes to parameter limits specified in TS. To meet 10 CFR 50.36(c)(2)(ii) requirements and alleviate the need for LARs to update parameter limits every fuel cycle, the NRC issued GL 88–16 with specific guidance for replacing the limit values for cycle-specific parameters in the TSs with references to an owner-controlled document, namely, the COLR. The guidance in GL 88–16 includes the following three actions:

1. The addition of the definition of a named formal report (i.e., Core Operating Limits Report) in TS that includes the values of cycle-specific parameter limits that have been established using an NRC-approved methodology and consistent with all applicable limits of the safety analyses.

2. The addition of an administrative reporting requirement (in TS 5.6.3) to submit the formal report on cycle-specific parameter limits to the Commission for information.

3. The modification of individual TS to note that the specific parameters shall be maintained within the limits provided in the defined formal report (COLR).

The proposed change has been evaluated against GL 88–16 and found to be consistent with that regulatory guidance.

3.0 TECHNICAL EVALUATION

TS LCO 3.4.1 specifies the limit values of the DNB parameters to assure that the pressurizer pressure, the RCS cold leg

temperature, and RCS flow rate during operation at rated thermal power (RTP) will be maintained within the limits assumed in the safety analyses in the final safety analysis report (FSAR). The safety analyses of anticipated operational occurrences (AOOs) and accidents assume initial conditions within the envelope of normal steady state operation at the RTP to demonstrate that the applicable acceptance criteria, including the specified acceptable fuel design limits (such as DNB ratio) and RCS pressure boundary design conditions, are met for each event analyzed. The TS limits placed on the DNB-related parameters ensure that these parameters, when appropriate measurement uncertainties are applied, will be bounded by those assumed in the safety analyses, and thereby provide assurance that the applicable acceptance criteria will not be violated should a transient or accident occur while operating at the RTP.

It is essential to safety that the plant is operated within the DNB parameter limits. This change retains the requirement to maintain the plant within the DNB parameter limits in LCO 3.4.1 along with the SR verification for each of the DNB parameters. As these parameter limits are calculated using NRC-approved methodologies and are consistent with all applicable limits of the plant safety analyses, this change does not affect nuclear safety.

TS 5.6.3, ''Core Operating Limits Report (COLR),'' specifies that the core operating limits shall be determined such that all applicable limits of the safety analyses are met, and that the analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC. This change modifies the list of NRC approved methodologies in TS 5.6.3 to include those used to calculate the DNB limits on pressurizer pressure, RCS cold leg temperature, and RCS total flow rate. The limit values of these parameters in the COLR will comply with existing operating fuel cycle analysis requirements, and are initial conditions assumed in safety analyses. Replacing of the DNB parameter values with references to the COLR does not lessen the requirement for compliance with all applicable limits.

Any revisions to the safety analyses that require prior NRC approval will be identified by the 10 CFR 50.59 review process. TS 5.6.3 also specifies that the COLR, including any midcycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC. This will allow NRC staff to continue trending the information even though prior NRC approval of the changes to these limits will not be required.

Section 50.36 requires LCOs to contain the lowest functional capability or performance levels of equipment for safe operation of the facility. The NRC staff finds that the proposed change to LCO 3.4.1 referencing the specific values of the DNB parameter limits in TS in the COLR continues to meet the regulatory requirement of 10 CFR 50.36(c)(2)(ii)(B) (Criterion 2), and follows the guidance described in GL 88–16. The NRC staff, therefore, concludes that this change is acceptable.

For safety analyses of transients or accidents, various sections of Chapter 15 of the Standard Review Plan (Ref. 7.3) specify that the reactor is initially at the RTP plus uncertainty, and the RCS flow is at nominal design flow including the measurement uncertainty. If one or more DNB parameter limits change, and these changes do not support the RTP, a license amendment would be required to either reduce the RTP or limit the plant operation at a level below the RTP. 10 CFR 50 Appendix K requires that the loss of coolant accident analysis be performed at 102% of the RTP. Other plant-specific analyses can contain an initial condition to be performed at RTP. To insure a clear understanding of this requirement the following statement has been added to TS 5.6.3: ''The maximum thermal power from the COLR shall be equal to or greater than the RTP defined in TS 1.1.''

4.0 STATE CONSULTATION

In accordance with the Commission's regulations, the [________] State official was notified of the proposed issuance of the amendment. The State official had [(1) no comments or (2) the following comments—with subsequent disposition by the staff].

5.0 ENVIRONMENTAL CONSIDERATION

The amendment[s] change[s] a requirement with respect to the installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 or surveillance requirements. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration and there has been no public comment on such finding published [DATE] ([ ] FR [ ]). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

6.0 CONCLUSION

The NRC staff has reviewed this proposed change to replace the values of the DNB parameters in TS with references to the COLR. This change will allow the licensee the flexibility to manage operating and core design margins associated with the DNB parameters without the need for cycle-specific LARs. Any future revisions to safety analyses that require prior NRC approval will be identified by the 10 CFR 50.59 review process. Based on this evaluation the NRC staff concludes that this change meets the regulatory requirements of 10 CFR 50.36, follows the guidance described in GL 88–16, and is acceptable.

7.0 REFERENCES

7.1 License Amendment Request dated [MMM, DD, YYYY], [Title of Amendment Request], ADAMS Accession No. [MLXXXXXXXXX].

7.2 Generic Letter 88–16 dated October 4, 1988, ''Removal of Cycle-Specific Parameter Limits from Technical Specifications,'' ADAMS Accession No ML041830597.

7.3 NUREG–0800, ''Standard Review Plan.''

Proposed No Significant Hazards Consideration Determination

Description of Amendment Request: [Plant name] requests adoption of an approved change to the standard technical specifications (STS) for Combustion Engineering Pressurized Water Reactor (PWR) Plants (NUREG–1432) and plant-specific technical specifications (TS), to allow replacing the departure from nucleate boiling (DNB) parameter limits with references to the core operating limits report (COLR) in accordance with Generic Letter 88–16, ''Removal of Cycle Specific Parameter Limits from Technical Specifications,'' dated October 4, 1988. The changes are consistent with NRC approved Industry/Technical Specification Task Force (TSTF) Standard Technical Specification Change Traveler, TSTF–487.

Basis for proposed no-significant-hazards-consideration determination: As required by 10 CFR 50.91(a), an analysis of the issue of no-significant-hazards-consideration is presented below:

Criterion 1: Does the Proposed Change Involve a Significant Increase in the Probability or Consequences of an Accident Previously Evaluated?

Response: No.

The proposed amendment replaces the limit values of the reactor coolant system (RCS) DNB parameters (i.e., pressurizer pressure, RCS cold leg temperature, and RCS flow rate) in TS with references to the COLR, in accordance with the guidance of Generic Letter 88–16, to allow these parameter limit values to be recalculated without a license amendment. The proposed amendment does not involve operation of any required structures, systems, or components (SSCs) in a manner or configuration different from those previously recognized or evaluated. The cycle-specific values in the COLR must be calculated using the NRC-approved methodologies listed in TS 5.6.5, ''Core Operating Limits Report (COLR).'' Replacing the RCS DNB parameter limits in TS with references to the COLR will maintain existing operating fuel cycle analysis requirements. Because these parameter limits are determined using the NRC-approved methodologies, the acceptance criteria established for the safety analyses of various transients and accidents will continue to be met. Therefore, neither the probability nor consequences of any accident previously evaluated will be increased by the proposed change.

Therefore, operation of the facility in accordance with the proposed amendment does not involve a significant increase in the probability or consequences of an accident previously evaluated.

Criterion 2: Does the Proposed Change Create the Possibility of a New or Different Kind of Accident from any Previously Evaluated?

Response: No.

The proposed amendment to replace the RCS DNB parameter limits in TS with references to the COLR does not involve a physical alteration of the plant, nor a change or addition of a system function. The proposed amendment does not involve operation of any required SSCs in a manner or configuration different from those previously recognized or evaluated. No new failure mechanisms will be introduced by the proposed change.

Therefore, the proposed amendment does not create the possibility of a new or different kind of accident from any accident previously evaluated.

Criterion 3: Does the Proposed Change Involve a Significant Reduction in the Margin of Safety?

Response: No.

The proposed amendment to replace the RCS DNB parameter limits in TS with references to the COLR will continue to maintain the margin of safety. The DNB parameter limits specified in the COLR will be determined based on the safety analyses of transients and accidents, performed using the NRC-approved methodologies that show that, with appropriate measurement uncertainties of these parameters accounted for, the acceptance criteria for each of the analyzed transients are met. This provides the same margin of safety as the limit values currently specified in the TS. Any future revisions to the safety analyses that require prior NRC approval are identified per the 10 CFR 50.59 review process.

Therefore, the proposed amendment would not involve a significant reduction in a margin of safety.

Based on the staff's review of the licensee's analysis, the staff concludes that the proposed amendment presents no significant hazards consideration under the standards set forth in 10 CFR 50.92(c) and, accordingly, a finding of ''no significant hazards consideration'' is justified.

[Lit. face SIG]

Dated at Rockville, Maryland this ______ day of ______ , 2007.

For The Nuclear Regulatory Commission.

Project Manager
Plant Licensing Branch [ ]
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

[FR Doc. E7–4752 Filed 3–14–07; 8:45 am]

BILLING CODE 7590–01–P

PENSION BENEFIT GUARANTY CORPORATION

Required Interest Rate Assumption for Determining Variable-Rate Premium for Single-Employer Plans; Interest Assumptions for Multiemployer Plan Valuations Following Mass Withdrawal

AGENCY: Pension Benefit Guaranty Corporation.

ACTION: Notice of interest rates and assumptions.

SUMMARY: This notice informs the public of the interest rates and assumptions to be used under certain Pension Benefit Guaranty Corporation regulations. These rates and assumptions are published elsewhere (or can be derived from rates published elsewhere), but are collected and published in this notice for the convenience of the public. Interest rates are also published on the PBGC's Web site (*http://www.pbgc.gov*).

DATES: The required interest rate for determining the variable-rate premium under part 4006 applies to premium payment years beginning in March 2007. The interest assumptions for performing multiemployer plan valuations following mass withdrawal under part 4281 apply to valuation dates occurring in April 2007.

FOR FURTHER INFORMATION CONTACT: Catherine B. Klion, Manager, Regulatory and Policy Division, Legislative and Regulatory Department, Pension Benefit Guaranty Corporation, 1200 K Street, NW., Washington, DC 20005, 202–326–4024. (TTY/TDD users may call the Federal relay service toll-free at 1–800–877–8339 and ask to be connected to 202–326–4024.)

SUPPLEMENTARY INFORMATION:

Variable-Rate Premiums

Section 4006(a)(3)(E)(iii)(II) of the Employee Retirement Income Security Act of 1974 (ERISA) and § 4006.4(b)(1) of the PBGC's regulation on Premium Rates (29 CFR part 4006) prescribe use of an assumed interest rate (the ''required interest rate'') in determining a single-employer plan's variable-rate premium. Pursuant to the Pension Protection Act of 2006, for premium payment years beginning in 2006 or 2007, the required interest rate is the ''applicable percentage'' of the annual rate of interest determined by the Secretary of the Treasury on amounts invested conservatively in long-term investment grade corporate bonds for the month preceding the beginning of the plan year for which premiums are being paid (the ''premium payment year'').

On February 2, 2007 (at 72 FR 4955), the Internal Revenue Service (IRS) published final regulations containing updated mortality tables for determining current liability under section 412(l)(7) of the Code and section 302(d)(7) of ERISA for plan years beginning on or after January 1, 2007. As a result, in accordance with section 4006(a)(3)(E)(iii)(II) of ERISA, the ''applicable percentage'' to be used in determining the required interest rate for plan years beginning in 2007 is 100 percent.

The required interest rate to be used in determining variable-rate premiums for premium payment years beginning in March 2007 is 5.85 percent (i.e., 100 percent of the 5.85 percent composite corporate bond rate for February 2007 as determined by the Treasury).

The following table lists the required interest rates to be used in determining variable-rate premiums for premium payment years beginning between April 2006 and March 2007.

For premium payment years beginning in:	The required interest rate is:
April 2006	5.01
May 2006	5.25
June 2006	5.35
July 2006	5.36
August 2006	5.36
September 2006	5.19
October 2006	5.06
November 2006	5.05
December 2006	4.90
January 2007	5.75
February 2007	5.89
March 2007	5.85

Multiemployer Plan Valuations Following Mass Withdrawal

The PBGC's regulation on Duties of Plan Sponsor Following Mass Withdrawal (29 CFR part 4281) prescribes the use of interest assumptions under the PBGC's regulation on Allocation of Assets in Single-Employer Plans (29 CFR part 4044). The interest assumptions applicable to valuation dates in April 2007 under part 4044 are contained in an amendment to part 4044 published elsewhere in today's **Federal Register**. Tables showing the assumptions applicable to prior periods are codified in appendix B to 29 CFR part 4044.

Issued in Washington, DC, on this 8th day of March 2007.

Vincent K. Snowbarger,

Interim Director, Pension Benefit Guaranty Corporation.

[FR Doc. E7–4679 Filed 3–14–07; 8:45 am]

BILLING CODE 7709–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. IC–27750; 812–13336]

Vanguard Bond Index Funds, et al.; Notice of Application

March 9, 2007.

AGENCY: Securities and Exchange Commission (''Commission'').

ACTION: Notice of an application for an order under section 6(c) of the Investment Company Act of 1940 (the ''Act'') for exemptions from sections 2(a)(32), 18(f)(1), 18(i), 22(d) and 24(d) of the Act and rule 22c–1 under the Act,

and under sections 6(c) and 17(b) of the Act for exemptions from sections 17(a)(1) and (2) of the Act.

SUMMARY OF APPLICATION: Applicants request an order that would permit the following: (a) An open-end management investment company, the series of which consist of the component securities of certain fixed income securities indices, to issue a class of shares (''ETF Shares'') that can be purchased from the investment company and redeemed only in large aggregations (''Creation Units''); (b) secondary market transactions in ETF Shares to occur at negotiated prices on a national securities exchange, as defined in section 2(a)(26) of the Act (''Exchange''); (c) dealers to sell ETF Shares to purchasers in the secondary market unaccompanied by a prospectus when prospectus delivery is not required by the Securities Act of 1933 (''Securities Act''); and (d) certain affiliated persons of the series to deposit securities into, and receive securities from, the series in connection with the purchase and redemption of Creation Units.

APPLICANTS: Vanguard Bond Index Funds (''Trust''), The Vanguard Group, Inc. (''VGI''), and Vanguard Marketing Corporation (''VMC'').

FILING DATES: The application was filed on October 25, 2006 and amended on January 23, 2007. Applicants have agreed to file an amendment during the notice period, the substance of which is reflected in the notice.

HEARING OR NOTIFICATION OF HEARING: An order granting the application will be issued unless the Commission orders a hearing. Interested persons may request a hearing by writing to the Commission's Secretary and serving applicants with a copy of the request, personally or by mail. Hearing requests should be received by the Commission by 5:30 p.m. on March 30, 2007, and should be accompanied by proof of service on applicants, in the form of an affidavit, or for lawyers, a certificate of service. Hearing requests should state the nature of the writer's interest, the reason for the request, and the issues contested. Persons who wish to be notified of a hearing may request notification by writing to the Commission's Secretary.

ADDRESSES: Secretary, U.S. Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090. Applicants, c/o Barry A. Mendelson, The Vanguard Group, Inc., P.O. Box 2600, Valley Forge, PA 19482.

FOR FURTHER INFORMATION CONTACT: Keith A. Gregory, Senior Counsel at (202) 551–6815, or Michael W. Mundt, Senior Special Counsel, at (202) 551–6821 (Division of Investment Management, Office of Investment Company Regulation).

SUPPLEMENTARY INFORMATION: The following is a summary of the application. The complete application may be obtained for a fee at the Commission's Public Reference Desk, 100 F Street, NE., Washington, DC 20549–0102, telephone (202) 551–5850.

Applicants' Representations

1. The Trust is an open-end management investment company registered under the Act and organized as a Delaware statutory trust. The Trust currently has four series (''Existing Funds''). Each Existing Fund currently offers separate classes of shares for retail and institutional investors (such classes of shares collectively, ''Conventional Shares''). In the future, the Trust or another registered open-end management investment company may offer other series (''Future Funds,'' and together with Existing Funds, ''Funds''). Any Future Fund will: (a) Be advised by VGI or an entity controlled by or under common control with VGI and (b) comply with the terms and conditions of any order granted pursuant to the application.

2. VGI is a Pennsylvania corporation that is wholly and jointly owned by 35 investment companies and the series of those investment companies (each series, a ''Vanguard Fund'' and collectively, the ''Vanguard Fund Complex''). VGI is registered as an investment adviser under the Investment Advisers Act of 1940 and as a transfer agent under the Securities Exchange Act of 1934 (''Exchange Act''). VGI provides each Vanguard Fund with corporate management, administrative, and transfer agency services at cost. VGI also provides advisory services at cost to certain Vanguard Funds, including each of the Existing Funds. VMC, a wholly owned subsidiary of VGI, is registered as a broker-dealer under the Exchange Act. VMC provides all distribution and marketing services to the Vanguard Funds, including each of the Existing Funds.

3. Each Existing Fund seeks to track as closely as possible the performance of a different index that measures the performance of the bond market as a whole or a discrete segment of the bond market (the ''Target Indexes'').[1] The bond holdings of each Existing Fund are selected through a sampling process and at least 80% (and in most cases more than 90%) of an Existing Fund's assets will be invested in bonds included in the Existing Fund's Target Index.[2] The remainder is typically invested in bonds that are not included in the Existing Fund's Target Index, cash and cash equivalents, futures, and swap contracts. Unlike the other three Existing Funds, the Vanguard Total Bond Market Index Fund (''Total Bond Market Index Fund'') holds government mortgage-backed securities (''MBS''), asset backed securities (''ABS''), and commercial mortgage-backed securities (''CMBS'').[3] The Total Bond Market Index Fund seeks to track that portion of the Lehman Agg. Index devoted to MBS by investing a corresponding percentage of its assets either in MBS included in the index or in ''to-be-announced'' (''TBA'') transactions on MBS.[4]

4. Applicants state that, historically, the difference between the performance of an Existing Fund and the performance of its Target Index has rarely exceeded one percentage point and in almost all cases has been significantly less than one percentage point. Applicants expect that, in the future, both the Existing Funds and Future Funds will track their Target Indexes with the same degree of precision, and will have a tracking error of less than 5% per annum. No entity that creates, compiles, sponsors, or maintains a Target Index is or will be an affiliated person, as defined in section 2(a)(3) of the Act, or an affiliated person of an affiliated person, of the Funds, VGI, any adviser to or promoter of a Fund, or VMC.

5. Each Fund proposes to create ETF Shares, a class of shares that would be listed on an Exchange and trade in the secondary market at negotiated prices. Applicants submit that the availability of ETF Shares would satisfy market

[1] The Target Indexes are Lehman Brothers Aggregate Bond Index ''Lehman Agg. Index''), Lehman Brothers 1–5 Year Government/Credit Index, Lehman Brothers 5–10 Year Government/Credit Index and Lehman Brothers Long Government/Credit Index.

[2] Each Fund invests in a representative sample of bonds from its Target Index that will resemble the full index in terms of characteristics such as maturity, credit quality, issuer type and yield.

[3] The Total Bond Market Index Fund will hold MBS, ABS, and CMBS in approxiamtely the same percentages as those securities are represented in the Lehman Agg. Index. ABS and CMBS will not be among the Deposit Securities required to purchase a Creation Unit or among the Redemption Securities an investor will receive when redeeming a Creation Unit.

[4] A ''TBA transaction'' is essentially a purchase or sale of an MBS for future settlement at an agreed-upon date. Applicants state that most MBS trades are executed as TBA transactions. Applicants state that TBA transactions increase the liquidity and pricing efficiency of transactions in MBS because they permit similar MBS to be traded interchangeably pursuant to commonly observed settlement and delivery requirements.

demand for investment company securities which would provide intra-day liquidity and low cost exposure to an index of bonds. Applicants state that, by creating an exchange-traded class of shares, the Funds will offer short-term investors an attractive means of investing in the Funds.[5] Applicants state that offering ETF Shares will benefit the Funds by reducing the portfolio disruption and transaction costs caused by short-term investors.

6. The Funds will issue ETF Shares only in Creation Units, aggregations of a specified number of shares ranging from 50,000 to 100,000 shares. The price of a Creation Unit will range from $1,500,000 to $10,000,000. Orders to purchase Creation Units must be placed with VMC by or through an ''Authorized Participant,'' which is a Depository Trust Company (''DTC'') participant that has executed a participant agreement with VMC. Creation Units will be issued in exchange for an in-kind deposit of securities and cash (''Creation Deposit'').[6] The Creation Deposit will consist of a basket of approximately 50 to 100 fixed income securities selected by VGI (''Deposit Securities'')[7] and a cash payment to equalize any difference between the total aggregate market value of the Deposit Securities and the NAV per Creation Unit of the Fund (''Purchase Balancing Amount'').[8] An investor purchasing a Creation Unit from a Fund will be charged a fee (''Transaction Fee'') to prevent any dilution of the interests of remaining shareholders due to the Fund incurring costs in connection with the investor's purchase of the Creation Unit(s).[9] Each purchaser of a Creation Unit will receive a prospectus for the ETF Shares (the ''ETF Prospectus'') that discloses the maximum Transaction Fee, and the method of calculating Transaction Fees will be disclosed in the Fund's Statement of Additional Information (''SAI''). A Fund's Conventional Shares will be covered by a separate prospectus (the ''Conventional Prospectus'').

7. The Funds will accept purchase orders only on days that the NYSE is open for business. Purchase orders must be received by VMC prior to the closing time of the regular trading session of the NYSE. VMC will transmit all purchase orders to the Funds, maintain a record of each Creation Unit purchaser, and send out an ETF Prospectus and confirmation to such purchasers.

8. The purchaser of a Creation Unit will be able to separate the Creation Unit into individual ETF Shares.[10] ETF Shares will be listed on an Exchange and traded in the secondary market in the same manner as shares of other exchange-traded funds. One or more Exchange specialists (''Specialists'') will be assigned to make a market in the ETF Shares. The price of ETF Shares traded on an Exchange will be based on a current bid/offer market, and each ETF Share is expected to have an initial market value of between $30 and $100. Transactions involving the sale of ETF Shares in the secondary market will be subject to customary brokerage commissions and charges.

9. Applicants expect that purchasers of Creation Units will include institutional investors and arbitrageurs. A Specialist, in providing for a fair and orderly secondary market for ETF Shares, also may purchase Creation Units for use in its market making activities on the Exchange. Applicants expect that secondary market purchasers of ETF Shares will include both institutional and retail investors.[11] Applicants believe that arbitrageurs will purchase or redeem Creation Units to take advantage of discrepancies between the ETF Shares' market price and the ETF Shares' NAV. Applicants expect that this arbitrage activity will provide a market discipline that will result in a close correspondence between the price at which the ETF Shares trade and their NAV. Applicants do not expect ETF Shares to trade at a significant premium or discount to their NAV.[12]

10. Applicants will make available an ETF Shares product description (''Product Description'') for distribution in accordance with an Exchange rule requiring Exchange members and member organizations effecting transactions in ETF Shares to deliver a Product Description to investors purchasing ETF Shares, whether on or away from the Exchange. Applicants state that any other Exchange that applies for unlisted trading privileges in ETF Shares will have to adopt a similar rule, requiring delivery of the Product Description. The Product Description will provide a plain English overview of a Fund, including its investment objective and investment strategies, the identity of VGI, the material risks of investing in the Fund, and the frequency of dividends and capital gains distributions. The Product Description also will provide a brief, plain English

[5] Applicants expect ETF Shares to appeal to short-term investors because they can be bought and sold continuously throughout the day at market price rather than at net asset value (''NAV''), which is calculated only once per day at the close of trading on the New York Stock Exchange (''NYSE''). Transactions in Conventional Shares will continue to be priced at NAV.

[6] On each business day, prior to the opening of trading on the Exchange, VGI will make available through the National Securities Clearing Corporation (''NSCC'') (or through some other party if NSCC is unwilling or unable to perform this function) the list of the names and the required amount of each Deposit Security to be included in the Creation Deposit for each Fund. Each Fund reserves the right to permit or require the purchaser of a Creation Unit to substitute cash or a different security to replace a Deposit Security under certain circumstances.

[7] Applicants state that it would be impractical to ask an Authorized Participant to assemble a basket of several hundred or several thousand bonds that replicate the portfolio of a Fund. Accordingly, VGI will select a subset of the Fund's portfolio using a representative sampling strategy.

[8] The Funds must comply with the federal securities laws in accepting Deposit Securities and satisfying redemptions with Redemption Securities (as defined below), including that the Deposit Securities and Redemption Securities are sold in transactions that would be exempt from registration under the Securities Act. If at any time in the future the Funds accept Deposit Securities or satisfy redemptions with Redemption Securities that are restricted securities eligible for resale pursuant to rule 144A under the Securities Act, the Funds will comply with the conditions of rule 144A, including in satisfying redemptions with such rule 144A eligible restricted Redemption Securities. The prospectus for the Funds will state that ''An Authorized Participant that is not a 'qualified institutional buyer' as defined in rule 144A under the Securities Act of 1933 will not be able to receive, as part of the redemption basket, restricted securities eligible for resale under rule 144A.''

[9] When a Fund permits an investor to substitute cash for a Deposit Security, the investor may be assessed a higher Transaction Fee to offset the increased cost to the Fund of buying the necessary Deposit Security for its portfolio.

[10] Applicants state that persons purchasing Creation Units will be cautioned in the ETF Prospectus that some activities on their part may, depending on the circumstances, result in their being deemed a statutory underwriter and subject them to the prospectus delivery and liability provisions of the Securities Act. For example, a broker-dealer firm and/or its client may be deemed a statutory underwriter if it purchases Creation Units from a Fund, breaks them down into the constituent ETF Shares, and sells ETF Shares directly to its customers, or if it chooses to couple the purchase of a supply of new ETF Shares with an active selling effort involving solicitation of secondary market demand for ETF Shares. The ETF Prospectus will state that whether a person is an underwriter depends on all the facts and circumstances pertaining to that person's activities. The ETF Prospectus also will state that broker-dealer firms should note that dealers who are not ''underwriters'' but are participating in a distribution (as contrasted to an ordinary secondary trading transaction), and thus dealing with ETF Shares that are part of an ''unsold allotment'' within the meaning of section 4(3)(C) of the Securities Act, would be unable to take advantage of the prospectus delivery exemption provided by section 4(3) of the Securities Act.

[11] ETF Shares will be registered in book-entry form only. DTC or its nominee will be the registered owner of all outstanding ETF Shares. Records reflecting the beneficial owners of ETF Shares will be maintained by DTC or its participants.

[12] Every 15 seconds throughout the trading day, the Exchange will disseminate via the facilities of the Consolidated Tape Association the market value of an ETF Share and, separate from the consolidated tape, the Exchange or another information provider will disseminate a calculation of the approximate NAV of an ETF Share. Applicants state that an investor comparing the two figures will be able to determine whether, and to what extent, ETF Shares are selling at a premium or discount to NAV.

description of the salient features of ETF Shares. The Product Description will advise investors that an ETF Prospectus and SAI may be obtained, without charge, from the investor's broker or from VMC. The Product Description also will identify a Web site address where investors can obtain information about the composition and compilation methodology of the Target Index. Applicants expect that the number of purchases of ETF Shares in which an investor will not receive a Product Description will not constitute a significant portion of the market activity in ETF Shares.

11. Except in connection with the liquidation of a Fund (or of a Fund's ETF Share class), ETF Shares will only be redeemable in Creation Units through each Fund. An investor redeeming a Creation Unit generally will receive (a) A basket of securities (''Redemption Securities''), which in most cases will be the same as the Deposit Securities required of investors purchasing Creation Units on the same day, and (b) a cash amount equal to the difference in the value of the Redemption Securities and the NAV of a Creation Unit, which in most cases will be the same as the Purchase Balancing Amount paid (or received) by investors purchasing Creation Units on the same day. A Fund may make redemptions partly in cash in lieu of transferring one or more Redemption Securities to a redeeming investor, if the Fund determines that such alternative is warranted. A Fund may make such a determination if, for example, a redeeming investor is unable, by law or policy, from owning a particular Redemption Security. In order to cover the Fund's transaction costs, redeeming investors will pay a Transaction Fee.[13]

Applicants' Legal Analysis

1. Applicants request an order under section 6(c) of the Act for exemptions from sections 2(a)(32), 18(f)(1), 18(i), 22(d) and 24(d) of the Act and rule 22c–1 under the Act; and under sections 6(c) and 17(b) of the Act for exemptions from sections 17(a)(1) and (2) of the Act.

2. Section 6(c) of the Act provides that the Commission may exempt any person, security, or transaction, or any class or classes of persons, securities, or transactions, from any provision or provisions of the Act, or any rule or regulation thereunder, if and to the extent that such exemption is necessary or appropriate in the public interest and consistent with the protection of investors and the purposes fairly intended by the policy and provisions of the Act.

Section 2(a)(32) of the Act

3. Section 2(a)(32) of the Act defines ''redeemable security'' as any security, other than short-term paper, under the terms of which the holder, upon its presentation to the issuer, is entitled to receive approximately his proportionate share of the issuer's current net assets, or the cash equivalent. Applicants request an order under section 6(c) to permit ETF Shares to be redeemed in Creation Units only. Applicants note that because of the arbitrage possibilities created by the redeemability of Creation Units, it is expected that the market price of an ETF Share will not vary much from its NAV.

Section 18(f)(1) and 18(i) of the Act

4. Section 18(f)(1) of the Act, in relevant part, prohibits a registered open-end company from issuing any class of ''senior security,'' which is defined in section 18(g) to include any stock of a class having a priority over any other class as to the distribution of assets or payment of dividends. Section 18(i) of the Act requires that every share of stock issued by a registered management company be voting stock, with the same voting rights as every other outstanding voting stock. Rule 18f–3 permits an open-end fund to issue multiple classes of shares representing interests in the same portfolio without seeking exemptive relief from section 18(f)(1) and 18(i), provided that the fund complies with certain requirements. Applicants state that they will comply in all respects with rule 18f–3, except the requirements that (a) Each class have the same rights and obligations as each other class (other than the differences allowed by the rule), and (b) if a class has a different distribution arrangement, the class must pay all of the expenses of the arrangement. Because applicants, therefore, may not rely on rule 18f–3, they request an exemption under section 6(c) from sections 18(f)(1) and 18(i).

5. Applicants state that there are four ways in which the Conventional Shares and ETF Shares of each Fund will have different rights: (a) Conventional Shares are individually redeemable, while ETF Shares will be redeemable in Creation Units only; (b) ETF Shares will be traded on an Exchange, while Conventional Shares will not; (c) Conventional Shares declare dividends daily, while ETF Shares will declare dividends monthly; and (d) although all shares classes of a Fund will pay dividends monthly, the payment date for the Conventional Shares will be the same as the ex dividend date (''ex date''), while the payment date for the ETF Share will be four days or more after the ex date. Applicants assert that different trading and redemption rights are necessary if their proposal is to have the desired benefits. Applicants note that a Fund's ETF Shares will be tradable on an Exchange and redeemable only in large aggregations in order to encourage short-term investors to conduct their trading activities in a way that does not disrupt the management of the Fund's portfolio. Applicants assert that there is no reason to make Conventional Shares tradable and that it would be counterproductive to facilitate the ability of market timers to disrupt a Fund by making ETF Shares individually redeemable.

6. Applicants state the proposal to declare dividends to the ETF Share class on a monthly basis, as opposed to on a daily basis for the Conventional Share class, will result in a higher net asset value (''NAV'') for the ETF Share class during a monthly period due to the presence of accrued but undistributed income.[14] Applicants submit that absent adjustment, this difference would result in a disproportionate allocation of a fund's income, realized capital gains and losses, and unrealized appreciation and depreciation (''Allocable Items'') to the ETF Shares relative to the Conventional Shares because such items are allocated among a fund's classes based upon relative net assets. Applicants intend to eliminate this potential inequality by allocating the Allocable Items on the basis of class-level net assets adjusted to factor out the differences introduced by the application of the different dividend policies (''Asset Adjustment''). Applicants submit that the use of the Asset Adjustment will ensure that the daily allocation of Allocable Items to ETF Shares and Conventional Shares is not distorted by the classes' differing dividend policies.[15] Applicants state

[13] Investors who redeem for cash, rather than in kind, may pay a higher Transaction Fee.

[14] When dividends are declared monthly, as opposed to daily, each day's accrued income is reflected as an increase in the shares' NAV. At the end of the month, when dividends are declared, the NAV drops by the amount of the dividend. By contrast, when dividends are declared daily, the amount of the daily income accrual is offset by a corresponding distribution payable liability. As a result, the net effect on the shares' NAV typically is zero.

[15] Applicants will not rely on the requested order until the board of trustees (''Board'') of each Fund has formally determined that, after applying the Asset Adjustment, the annualized rates of return of the ETF and Conventional Share classes generally will differ only by the expense differentials among the classes, as required by rule 18f–3(c)(1)(v) under the Act.

that it is industry practice for bond ETFs to declare dividends monthly.

7. Applicants state that the accrual of dividends in the NAV of the ETF Shares but not the Conventional Shares will have an effect on the voting power of the respective classes because the shareholders of the Funds are given voting rights proportionate to the NAV of their shares. Applicants assert that such effects on voting power will be minor and that this treatment of voting rights meets the standards of section 18(i) because every share issued by the Funds will have equal voting rights in that each share will be entitled to one vote per dollar of NAV and a fractional vote per fractional dollar of NAV.

8. Applicants state that although Conventional Shares and ETF Shares both pay dividends monthly, another difference between the classes is that the holders of Conventional Shares are able to reinvest dividends immediately when paid, while the ETF Shareholders would have to wait a few days to receive their payments through their brokers. As a result, holders of Conventional Shares of the Funds who reinvest will be continuously invested, while ETF Shareholders who reinvest will be ''out of the market'' for four days with respect to the amount of the dividend.[16] Applicants state that the four day difference will affect the relative performance of the classes because during the time the dividend is out of the market, ETF Shareholders will not receive income or experience appreciation or depreciation on the amount of the dividend. Applicants do not expect this economic difference to be significant.

9. Applicants assert that the different rights do not implicate the concerns underlying section 18 of the Act, including excessive leverage, conflicts of interest and investor confusion. With respect to the potential for investor confusion, applicants will take a variety of steps to ensure that investors understand the key differences between Conventional Shares and ETF Shares. Applicants state that the ETF Shares will not be marketed as a mutual fund investment. Marketing materials may refer to ETF Shares as an interest in an investment company or fund, but will not make reference to an ''open-end fund'' or ''mutual fund,'' except to compare or contrast the ETF Shares with the shares of a conventional open-end management investment company. Any marketing or advertising materials addressed primarily to prospective investors will emphasize that (a) ETF Shares are not redeemable from a Fund other than in Creation Units, (b) ETF Shares, other than in Creation Units, may be sold only through a broker, and the shareholder may have to pay brokerage commissions in connection with the sale, and (c) a selling shareholder may receive less than NAV in connection with the sale of ETF Shares. The same type of disclosure will be provided in the Conventional Prospectus, ETF Prospectus, Product Description, SAI, and any document addressed primarily to prospective investors. The prospectus for the Fund's Conventional Shares will disclose that dividends are declared daily and paid monthly. The prospectus and Product Description for the ETF Shares will disclose that dividends are declared monthly and paid monthly and that the reinvestment of dividends (if elected), will not occur until approximately four days after the ex date. The applicants also note that (a) All references to a Fund's exchange-traded class of shares will use a form of the name ''ETF Shares'' rather than the Fund name, (b) the cover and summary page of the ETF Prospectus will state that the ETF Shares are listed on an Exchange and are not individually redeemable, (c) VMC will only market Conventional Shares and ETF Shares in the same advertisement or marketing material when the advertisement or marketing material contains appropriate disclosure explaining the relevant features of each class of shares and highlighting the differences between the share classes, and (d) applicants have prepared educational materials describing the ETF Shares.

10. Applicants currently allocate distribution expenses among funds in the Vanguard Fund Complex according to a cost-sharing formula approved by the Commission in 1981 as part of an order allowing the Vanguard Fund Complex to internalize its distribution services (''1981 Order'').[17] For those funds in the Vanguard Fund Complex offering multiple classes of shares, applicants apply the formula in the 1981 Order by treating each class as a separate fund (''Multi-Class Distribution Formula'').

11. Applicants propose to apply the Multi-Class Distribution Formula to each Fund's class of ETF Shares. Applicants acknowledge that, because ETF Shares may have a distribution arrangement that differs from that for Conventional Shares, the proposed allocation method is inconsistent with rule 18f–3. Applicants contend, however, that the Multi-Class Distribution Formula is a fundamental feature of Vanguard's unique, internally-managed structure, and that the proposed allocation method is consistent with the method approved by the Commission in the 1981 Order. The Multi-Class Distribution Formula has been approved by the Board of each Fund, and the Board of each Fund, including a majority of the trustees who are not interested persons, as defined in section 2(a)(19) of the Act (''Disinterested Trustees''), will review the application of the Multi-Class Distribution Formula on an annual basis and determine that the proposed allocation is in the best interests of each class of shareholders and of the Fund as a whole.

Section 22(d) of the Act and Rule 22c–1 Under the Act

12. Section 22(d), among other things, prohibits a dealer from selling a redeemable security that is currently being offered to the public by or through an underwriter, except at a current public offering price described in the prospectus. Rule 22c–1 generally requires that a dealer selling, redeeming, or repurchasing a redeemable security do so only at a price based on its NAV. Applicants state that secondary market trading in ETF Shares will take place at negotiated prices, not at a current offering price described in the ETF Prospectus, and not at a price based on NAV. Thus, purchases and sales of ETF Shares in the secondary market will not comply with section 22(d) and rule 22c–1. Accordingly, applicants request exemptions from these provisions under section 6(c) of the Act.

13. Applicants assert that the sale of ETF Shares at negotiated prices does not present the opportunity for any of the abuses that section 22(d) and rule 22c–1 were designed to prevent. Applicants maintain that while there is little legislative history regarding section 22(d), its provisions, as well as those of rule 22c–1, appear to have been designed to (a) Prevent dilution caused by certain riskless trading schemes by

[16] Applicants assert that the delay between the ex date and the payment/reinvestment date occurs for all ETFs, whether they are stand-alone ETFs or part of a multi-class structure, and regardless of whether an ETF Shareholder elects to reinvest dividends.

[17] Investment Company Act Release No. 11645 (Feb. 25, 1981) (Opinion of the Commission and Final Order). Under the formula, each Vanguard Fund's contribution is based 50% on its average month-end net assets during the preceding quarter relative to the average month-end net assets of the other Vanguard Funds, and 50% on its sales of new shares relative to the sales of new shares of the other Vanguard Funds during the preceding 24 months. So that a new fund is not unduly burdened, the formula caps each Vanguard Fund's contribution at 125% of the average expenses of the Vanguard Funds collectively, with any amounts above the cap redistributed among the other Vanguard Funds. In addition, no fund may pay more than 0.2% of its average month-end net assets for distribution.

principal underwriters and contract dealers, (b) prevent unjust discrimination or preferential treatment among buyers resulting from sales at different prices, and (c) ensure an orderly distribution of investment company shares by eliminating price competition from dealers offering shares at less than the published sales price and repurchasing shares at more than the published redemption price. Applicants state that secondary market trading in ETF Shares would not cause dilution for existing Fund shareholders because such transactions would not directly or indirectly affect the Fund's assets. Applicants further state that secondary market trading in ETF Shares would not lead to discrimination or preferential treatment among purchasers because, to the extent that different prices exist during a given trading day or from day to day, these variances will occur as a result of market forces. Finally, applicants contend that the proposed distribution system will be orderly because, among other things, arbitrage activity will ensure that the difference between the market price of ETF Shares and their NAV remains narrow.

Section 24(d) of the Act

14. Section 24(d) provides, in relevant part, that the prospectus delivery exemption provided to dealer transactions by section 4(3) of the Securities Act does not apply to transactions in a redeemable security issued by an open-end investment company. Applicants request an exemption under section 6(c) of the Act from section 24(d) to permit dealers selling ETF Shares to rely on the prospectus delivery exemption provided by section 4(3) of the Securities Act.[18]

15. Applicants state that ETF Shares will be listed on an Exchange and will be traded in a manner similar to other equity securities, including the shares of closed-end investment companies. Applicants note that dealers selling shares of closed-end investment companies in the secondary market generally are not required to deliver a prospectus to the purchaser. Applicants contend that ETF Shares, as a listed security, merit similar treatment, reducing compliance costs and regulatory burdens that result from the imposition of a prospectus delivery requirement on secondary market transactions. Applicants state that because ETF Shares will be exchange-listed, prospective investors will have access to several types of market information about the ETF Shares. Applicants state that information regarding market price and volume will be continually available on a real-time basis throughout the day on brokers' computer screens and other electronic services. The previous day's price and volume information also will be published daily in the financial section of newspapers.

16. Applicants further state that investors that purchase ETF Shares in the secondary market will receive a Product Description, describing the Fund and its ETF Shares. Applicants state that, while not intended as a substitute for a prospectus, the Product Description will contain information about ETF Shares that is tailored to meet the needs of investors purchasing ETF Shares in the secondary market.

Sections 17(a)(1) and (2) of the Act

17. Sections 17(a)(1) and (2) generally prohibit an affiliated person of a registered investment company, or an affiliated person of an affiliated person, acting as principal, from selling any security to, or purchasing any security from, the company. Sections 2(a)(3)(A) and (C) of the Act define ''affiliated person,'' respectively, as any person who owns 5% or more of an issuer's outstanding voting securities and any person who controls the fund. Section 2(a)(9) of the Act provides that a control relationship will be presumed where one person owns 25% or more of another person's voting securities. Applicants state that a large institutional investor or the Specialist could own 5% or more, or more than 25%, of a Fund's outstanding voting securities and, as a result, be deemed to be an affiliated person of the Fund under section 2(a)(3)(A) or (C). Applicants further state that, because purchases and redemptions of Creation Units would be in-kind, rather than for cash, those investors would be precluded by sections 17(a)(1) and (2) from purchasing or redeeming Creation Units from the Fund. Accordingly, applicants request an exemption under sections 6(c) and 17(b) of the Act to permit these affiliated persons, and affiliated persons of such affiliated persons who are not otherwise affiliated with the Fund, to purchase and redeem Creation Units through in-kind transactions.

18. Section 17(b) of the Act authorizes the Commission to exempt a proposed transaction from section 17(a) if evidence establishes that the terms of the transaction, including the consideration to be paid or received, are reasonable and fair and do not involve overreaching, and the proposed transaction is consistent with the policies of the registered investment company involved and the general purposes of the Act. Applicants contend that no useful purpose would be served by prohibiting persons affiliated with a Fund, as described above, from purchasing or redeeming Creation Units from the Fund. Applicants represent that Fund affiliates making in-kind purchases and redemptions would be treated no differently from non-affiliates making the same types of transactions. Applicants state that all purchases and redemptions of Creation Units would be at the Fund's next calculated NAV. Applicants also state that, in all cases, Deposit Securities and Redemption Securities will be valued in the same manner and using the same standards as those securities are valued for purposes of calculating the Fund's NAV. Applicants assert that, for these reasons, the requested relief meets the standards of sections 6(c) and 17(b).

Applicants' Conditions

Applicants agree that the order granting the requested relief will be subject to the following conditions:

1. The ETF Shares Prospectus and the Product Description for each Fund will clearly disclose that, for purposes of the Act, ETF Shares are issued by the Fund and the acquisition of ETF Shares by investment companies is subject to the restrictions of section 12(d)(1) of the Act, except as permitted by an exemptive order that permits registered investment companies to invest in a Fund beyond the limits of section 12(d)(1), subject to certain terms and conditions.

2. As long as a Fund operates in reliance on the requested order, the ETF Shares will be listed on an Exchange.

3. The ETF Shares of a Fund will not be advertised or marketed as shares of an open-end investment company or mutual fund. The ETF Shares Prospectus of each Fund will prominently disclose that ETF Shares are not individually redeemable and will disclose that holders of ETF Shares may acquire the shares from the Fund and tender the shares for redemption to the Fund in Creation Unit aggregations only. Any advertising material that describes the purchase or sale of Creation Units or refers to redeemability will prominently disclose that ETF Shares are not individually redeemable and that holders of ETF Shares may acquire the shares from the Fund and tender the shares for redemption to the Fund in Creation Unit aggregations only.

[18] Applicants do not seek relief from the prospectus delivery requirement for non-secondary market transactions, including purchases of Creation Units or those involving an underwriter.

4. Before a Fund may rely on the order, the Commission will have approved, pursuant to rule 19b–4 under the Exchange Act, an Exchange rule requiring Exchange members and member organizations effecting transactions in ETF Shares to deliver a Product Description to purchasers of ETF Shares.

5. On an annual basis the Board of each Fund, including a majority of Disinterested Trustees, must determine, for each Fund, that the allocation of distribution expenses among the classes of Conventional Shares and ETF Shares in accordance with the Multi-Class Distribution Formula is in the best interests of each class and of the Fund as a whole. Each Fund will preserve for a period of not less than six years from the date of a Board determination, the first two years in an easily accessible place, a record of the determination and the basis and information upon which the determination was made. This record will be subject to examination by the Commission and its staff.

6. Applicants' Web site, which is and will be publicly accessible at no charge, will contain the following information, on a per ETF Share basis, for each Fund: (a) The prior business day's closing NAV and the midpoint of the bid-asked spread at the time the Fund's NAV is calculated (''Bid-Asked Price'') and a calculation of the premium or discount of the Bid-Asked Price in relation to the closing NAV; and (b) data for a period covering at least the four previous calendar quarters (or the life of a Fund, if shorter) indicating how frequently each Fund's ETF Shares traded at a premium or discount to NAV based on the Bid-Asked Price and closing NAV, and the magnitude of such premiums and discounts. In addition, the Product Description for each Fund will state that applicants' Web site has information about the premiums and discounts at which the Fund's ETF Shares have traded.

7. The ETF Shares Prospectus and annual report will include, for each Fund: (a) The information listed in condition 6(b), (i) In the case of the ETF Shares Prospectus, for the most recently completed calendar year (and the most recently completed quarter or quarters, as applicable), and (ii) in the case of the annual report, for no less than the immediately preceding five fiscal years (or the life of the Fund, if shorter); and (b) the cumulative total return and the average annual total return for one, five and ten year periods (or the life of the Fund, if shorter) of (i) an ETF Share based on NAV and the Bid-Asked Price and (ii) the Fund's Target Index.

For the Commission, by the Division of Investment Management, pursuant to delegated authority.

Florence E. Harmon,

Deputy Secretary.

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SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–55437; File No. SR–Amex–2006–118]

Self-Regulatory Organizations; American Stock Exchange LLC; Notice of Filing of Amendment Nos. 2 and 3 to Proposed Rule Change Relating to Generic Listing Standards for Series of Portfolio Depositary Receipts and Index Fund Shares Based on Fixed Income Indexes and Accelerated Approval of Proposed Rule Change as Amended

March 9, 2007.

I. Introduction

On December 22, 2006, the American Stock Exchange LLC (''Amex'' or ''Exchange'') filed with the Securities and Exchange Commission (''Commission''), pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'')[1] and Rule 19b–4 thereunder,[2] a proposed rule change relating to generic listing standards for series of portfolio depositary receipts (''PDRs'') and index fund shares (''IFSs''), together referred to as ''exchange-traded funds'' (''ETFs''), based on fixed income indexes. On January 26, 2007, the Exchange filed Amendment No. 1. The proposed rule change, as amended, was published for comment in the **Federal Register** on February 7, 2007 for a 15-day comment period.[3] The Commission received no comments on the proposal. On March 2, 2007, Amex filed Amendment No. 2 to the proposed rule change[4] and on March 7, 2007, Amex filed Amendment No. 3 to the proposed rule change.[5] This order provides notice of the proposed rule change as modified by Amendments No. 1, 2, and 3 and approves the proposed rule change as amended on an accelerated basis.

II. Description of the Proposal

The Exchange proposes to revise Amex Rules 1000–AEMI and 1000A–AEMI to include generic listing standards to permit the listing and trading of ETFs that are based on indexes or portfolios consisting of fixed income securities (''Fixed Income Indexes'') or both fixed income and equity securities (''Combination Indexes'') pursuant to Rule 19b–4(e) under the Act.[6] Specifically, the Exchange proposes to add Commentaries .04, .05, and .06 to Amex Rule 1000–AEMI and Commentaries .03, .04, and .05 to Amex Rule 1000A–AEMI and to revise the definitions of PDR and IFS, in Amex Rules 1000–AEMI(b)(1) and 1000A–AEMI(b)(1), respectively, to include ETFs based on Fixed Income Indexes and Combination Indexes.

The proposed rule change will enable the Exchange to list and trade an ETF pursuant to Rule 19b–4(e) under the Act without a rule filing if each of the conditions set forth in either Commentaries .04 and .05 to Rule 1000–AEMI or Commentaries .03 and .04 to Rule 1000A–AEMI, as applicable, is satisfied. The proposed listing standards will apply to certain Fixed Income Indexes and Combination Indexes that the Commission has yet to review, as well as those Fixed Income Indexes described in exchange rules that have previously been approved by the Commission under Section 19(b)(2) of the Act[7] for the trading of ETFs, options, or other index-based securities.[8]

A. Generic Listing Standards

Rule 19b–4(e) under the Act provides that the listing and trading of a new derivative securities product by a self-

[1] 15 U.S.C. 78s(b)(l).

[2] 17 CFR 240.19b–4.

[3] *See* Securities Exchange Act Release No. 55213 (January 31, 2007), 72 FR 5768 (''Notice'').

[4] In Amendment No. 2, the Exchange (1) Updated its proposal to reflect the migration of ETF shares from Amex's legacy platform to the AEMI platform and (2) represented that an ETF based on a fixed income index or combination index would be covered under the Exchange's existing surveillance program for ETFs and that all products listed under the proposed generic listing standards would be subject to the full panoply of Amex rules and procedures that now govern the trading of ETFs on Amex.

[5] In Amendment No. 3, the Exchange revised proposed Commentary .06(g) to Rule 1000–AEMI and proposed Commentary .05(g) to Rule 1000A–AEMI to clarify that Rule 1000–AEMI and Rules 1001 through 1006 as well as Rule 1000A–AEMI and Rules 1001A through 1005A apply to the listing and trading of fixed income and combination index ETFs.

[6] 17 CFR 240.19b–4(e).

[7] 15 U.S.C. 78s(b)(2).

[8] *See* proposed Commentary .04 to Amex Rule 1000–AEMI and Commentary .03 to Amex Rule 1000A–AEMI (permitting the Exchange to list and trade an ETF pursuant to Rule 19b–4(e) provided that the portfolio or index ''has been reviewed and approved for the trading of options, Portfolio Depository Receipts, Index Fund Shares, Index-Linked Exchangeable Notes or Index-Linked Securities by the Commission under Section 19(b)(2) of the Securities Exchange Act of 1934 and rules thereunder and the conditions set forth in the Commission's approval order, continue to be satisfied. * * *'').

regulatory organization shall not be deemed a proposed rule change, pursuant to paragraph (c)(1) of Rule 19b–4,[9] if the Commission has approved, pursuant to Section 19(b) of the Act,[10] the self-regulatory organization's trading rules, procedures, and listing standards for the product class that would include the new derivatives securities product, and the self-regulatory organization has a surveillance program for the product class.[11]

The Exchange already has Commission-approved generic listing standards for ETFs based on indexes that consist of stocks listed on U.S. and non-U.S. exchanges,[12] for trust certificates linked to certain Fixed Income Securities,[13] and for other index-based derivatives.[14] The Commission has also approved for listing and trading on the Exchange ETFs based on certain Fixed Income Indexes [15] and structured notes linked to a basket or index of Fixed Income Securities.[16] This proposal seeks to adopt listing standards, trading rules, and procedures, including surveillance, for ETFs based on Fixed Income and Combination Indexes that generally reflect existing generic listing standards for ETFs based on equities, but are tailored for the fixed income markets.[17]

B. Exchange-Traded Funds

Amex Rules 1000–AEMI and Rules 1001 *et seq.* allow for the listing and trading on the Exchange of PDRs. A PDR represents an interest in a unit investment trust registered under the Investment Company Act of 1940 (the ''1940 Act'') [18] that operates on an open-end basis and holds the securities that comprise an index or portfolio. Amex Rules 1000A–AEMI and 1001A *et seq.* provide standards for listing IFSs, which are securities issued by an open-end management investment company (*i.e.*, an open-end mutual fund) based on a portfolio of securities that seeks to provide investment results that correspond generally to the price and yield performance or total return performance of a specified foreign or domestic stock index or fixed income index. Pursuant to these rules, ETF shares must be issued in a specified aggregate minimum number in return for a deposit of specified securities and/or a cash amount, with a value equal to the next-determined net asset value (''NAV''). When aggregated in the same specified minimum number, ETF shares must be redeemed by the issuer for the securities and/or cash, with a value equal to the next-determined NAV. Consistent with Amex Rules 1002 and 1002A, the NAV is calculated once a day after the close of the regular trading day.

To meet the investment objective of providing investment returns that correspond to the performance of the underlying index, an ETF may use a ''replication'' strategy or a ''representative sampling'' strategy with respect to the ETF portfolio. An ETF using a replication strategy invests in each component security of the underlying index in about the same proportion as that security is represented in the index itself. An ETF using a representative sampling strategy generally invests in a significant number, but perhaps not all, of the component securities of the underlying index, and holds securities that, in the aggregate, are intended to approximate the full index in terms of certain key characteristics. In the context of a fixed income index, such characteristics may include liquidity, duration, maturity, and yield.

In addition, an ETF portfolio may be adjusted in accordance with changes in the composition of the underlying index or to maintain compliance with requirements applicable to a regulated investment company under the Internal Revenue Code (''IRC'').

C. Listing and Trading of ETFs Based on Fixed Income Indexes or Fixed Income Securities

Proposed Commentary .04 to Amex Rule 1000–AEMI and Commentary .03 to Amex Rule 1000A–AEMI define the term ''Fixed Income Securities'' to include notes, bonds (including convertible bonds), debentures, or evidence of indebtedness that include, but are not limited to, U.S. Treasury securities (''Treasury Securities''), securities of government-sponsored entities (''GSE Securities''), municipal securities, trust-preferred securities,[19] supranational debt,[20] and debt of a foreign country or subdivision thereof. For purposes of the proposed definition, a convertible bond is deemed to be a Fixed Income Security until it is converted into its underlying common or preferred stock.[21] Once converted, the equity security may no longer continue as a component of a fixed income index under the proposed rules and, accordingly, would have to be removed from such index for the ETF to remain listed pursuant to proposed Commentary .04 to Amex Rule 1000–AEMI or Commentary .03 to Amex Rule 1000A–AEMI.

[9] 17 CFR 240.19b–4(c)(1).

[10] 15 U.S.C. 78s(b).

[11] *See* Securities Exchange Act Release No. 40761 (December 8, 1998), 63 FR 70952 (December 22, 1998) (''New Products Release'').

[12] *See* Securities Exchange Act Release Nos. 54739 (November 9, 2006), 71 FR 66993 (November 17, 2006) (for ETFs based on global and international indexes); and 42787 (May 15, 2000), 65 FR 33598 (May 24, 2000) (for ETFs based on indexes comprised of U.S. stocks).

[13] *See* Securities Exchange Act Release No. 50355 (September 13, 2004), 69 FR 56252 (September 20, 2004) (approving generic listing standards for trust certificates linked to portfolios of investment-grade debt securities, securities of government-sponsored entities, and U.S. Treasury securities).

[14] *See* Amex Company Guide Section 107D (Index-Linked Securities); Securities Exchange Act Release No. 51563 (April 15, 2005), 70 FR 21257 (April 25, 2005). Such listing standards permit the listing—pursuant to Rule 19b–4(e) under the Act—of such securities where the Commission had previously approved the trading of specified index-based derivatives on the same index, on the condition that all of the standards set forth in the original order are satisfied by the exchange employing generic listing standards.

[15] *See* Securities Exchange Act Release Nos. 46252 (July 24, 2002), 67 FR 49715 (July 31, 2002) (approving the listing and trading of funds based on U.S. Treasury or corporate bond indexes); 46738 (October 29, 2002), 67 FR 67666 (November 6, 2002) (approving the listing and trading of FITRs); and 52870 (December 1, 2005), 70 FR 73039 (December 8, 2005) (approving the trading on a UTP basis of the iShares Lehman TIPS Bond Fund).

[16] *See* Securities Exchange Act Release Nos. 41334 (April 27, 1999), 64 FR 23883 (May 4, 1999) (approving the listing and trading of Bond Indexed Term Notes); 46923 (November 27, 2002), 67 FR 72247 (December 4, 2002) (approving the listing and trading of trust units linked to a basket of investment-grade fixed income securities); and 48484 (September 11, 2003), 68 FR 54508 (September 17, 2003) (approving the listing and trading of trust certificates linked to a basket of up to five investment-grade fixed income securities plus U.S. Treasury securities).

[17] The failure of a particular ETF to comply with the proposed generic listing standards would not preclude the Exchange from submitting a separate rule change pursuant to Section 19(b)(2) of the Act to list and trade the ETF.

[18] 15 U.S.C. 80a.

[19] Trust-preferred securities are undated cumulative securities issued from a special purpose trust in which a bank or bank holding company owns all of the common securities. The trust's sole asset is a subordinated note issued by the bank or bank holding company. Trust preferred securities are treated as debt for tax purposes so that the distributions or dividends paid are a tax-deductible interest expense.

[20] Supranational debt represents the debt of international organizations such as the World Bank, the International Monetary Fund, regional multilateral development banks, and multilateral financial institutions. Examples of regional multilateral development banks include the African Development Bank, Asian Development Bank, European Bank for Reconstruction and Development, and the Inter-American Development Bank. In addition, examples of multilateral financial institutions include the European Investment Bank and the International Fund for Agricultural Development.

[21] Under the Section 3(a)(11) of the Act, 15 U.S.C. 78c(a)(11), a convertible security is an equity security. However, for the purposes of the proposed generic listing criteria, Amex believes that defining a convertible security (prior to its conversion) as a Fixed Income Security is consistent with the objectives and intention of the generic listing standards for fixed-income-based ETFs as well as the Act.

Fixed Income Index Criteria

To list an ETF pursuant to the proposed generic listing standards for Fixed Income Indexes, the index underlying the ETF must satisfy all the conditions contained in proposed Commentary .04 to Amex Rule 1000–AEMI (for PDRs) or proposed Commentary .03 to Amex Rule 1000A–AEMI (for IFSs). As with existing generic listing standards for ETFs based on domestic and international or global indexes, these listing criteria are designed to ensure that securities with substantial market distribution and liquidity account for a substantial portion of the weight of a Fixed Income Index.[22]

To list an ETF based on a Fixed Income Index pursuant to the proposed generic listing standards, the index must meet the following criteria:

- The index or portfolio must consist of Fixed Income Securities;
- Components that in aggregate account for at least 75% of the weight of the index or portfolio must have a minimum original principal amount outstanding of $100 million or more; [23]
- No component Fixed Income Security (excluding a Treasury Security) represents more than 30% of the weight of the index, and the five highest weighted component fixed income securities in the index do not in the aggregate account for more than 65% of the weight of the index; [24]
- An underlying index or portfolio (excluding one consisting entirely of exempted securities) must include a minimum of 13 non-affiliated issuers; [25] and
- Component securities that in aggregate account for at least 90% of the weight of the index or portfolio must be either: [26]
- From issuers that are required to file reports pursuant to Sections 13 and 15(d) of the Act; [27]
- From issuers that have a worldwide market value of its outstanding common equity held by non-affiliates of $700 million or more;
- From issuers that have outstanding securities that are notes, bonds, debentures, or evidences of indebtedness having a total remaining principal amount of at least $1 billion;
- Exempted securities, as defined in Section 3(a)(12) of the Act; [28] or
- From issuers that are governments of foreign countries or political subdivisions of foreign countries.

The proposed generic listing requirements for ETFs based on Fixed Income Indexes would not require that component securities in an underlying index have an investment-grade rating.[29] In addition, the proposed requirements would not require a minimum trading volume, due to the lower trading volume that generally occurs in the fixed income markets as compared to the equity markets.[30] Also, consistent with the existing Amex Rule 1000A–AEMI(b)(2)(iii), an IFS based on a Fixed Income Index or Combination Index that seeks to provide investment results that either exceed the performance of such underlying index or correspond to the inverse (opposite) of the performance of such index by a specified multiple may not be listed and traded pursuant to the proposed generic listing standards.

D. Listing and Trading of ETFs Based on Combination Indexes

To list an ETF pursuant to the proposed generic listing standards for Combination Indexes, an index underlying the ETF must satisfy all the conditions contained in proposed Commentary .05 to Amex Rule 1000–AEMI (for PDRs) or proposed Commentary .04 to Amex Rule 1000A–AEMI (for IFSs). As with ETFs based solely on Fixed Income Indexes, the generic listing standards are intended to ensure that securities with substantial market distribution and liquidity account for a substantial portion of the weight of both the equity and fixed income portions of a Combination Index.

The proposed rules provide that the Exchange may list and trade ETFs based on a combination of indexes or a series of component securities representing the U.S. or domestic equity market, the international equity market, and the fixed income market, pursuant to Rule 19b–4(e) under the Act, provided that: (i) Such portfolio or combination of indexes has been described in an exchange rule approved by the Commission for the trading of options, PDRs, IFSs, Index-Linked Exchangeable Notes, or Index-Linked Securities, and all of the standards set forth in the approval order are satisfied by the exchange employing generic listing standards; or (ii) the equity portion and fixed income portion of the component securities separately meet the criteria set forth in Commentary .03 (equities) and proposed Commentary .04 (fixed income) for PDRs and Commentary .02 (equities) and proposed Commentary .03 (fixed income) for IFSs.[31]

E. Index Maintenance and Information

The Exchange proposes to adopt Commentaries .04(b) and .05(a) to Amex Rule 1000–AEMI and Commentaries .03(b) and .04(a) to Amex Rule 1000A–AEMI to establish requirements regarding the maintenance and dissemination of index information in connection with ETFs based on Fixed Income Indexes and Combination Indexes.

Commentaries .04(b)(ii) and .05(a)(ii) to Amex Rule 1000–AEMI and Commentaries .03(b)(ii) and .04(a)(ii) to Amex Rule 1000A–AEMI would require that the underlying value of a Fixed Income Index be widely disseminated by one or more major market data vendors at least once a day during the time when the corresponding ETF trades on the Exchange. The rules also require that the underlying value of a Combination Index be widely disseminated by one or more major market data vendors at least once every 15 seconds during the time when the corresponding ETF trades on the Exchange, provided that, with respect to the fixed income components of the Combination Index, their impact on the index is required to be updated only once each day. In its proposal, the Exchange stated that these provisions reflect the nature of the fixed income markets as well as the frequency of intra-day trading information with respect to Fixed Income Securities. If

[22] The Exchange noted in its proposal that the index criteria are loosely based on the standards contained in Commission and Commodity Futures Trading Commission (''CFTC'') rules regarding the application of the definition of narrow-based security index to debt security indexes. *See* Securities Exchange Act Release No. 54106 (July 6, 2006), 71 FR 39534 (July 13, 2006) (File No. S7–07–06) (the ''Joint Rules'').

[23] This is virtually identical to the corresponding standard in Section 107E(a)(x) of the Amex *Company Guide* for trust certificates.

[24] This is consistent with the standard for U.S. equity ETFs set forth in Commentary .03(a)(A) to Amex Rule 1000–AEMI and Commentary .02(a)(A) to Amex Rule 1000A–AEMI and the standard set forth by the Commission and the CFTC in the Joint Rules. *See* note 22 *supra*.

[25] The required number of unaffiliated issuers parallels the diversification requirement applicable to U.S. equity ETFs as set forth in Commentary .03(a)(A) to Amex Rule 1000–AEMI and Commentary .02(a)(A) to Amex Rule 1000A–AEMI.

[26] The Exchange notes that this proposed standard is consistent with a similar standard in the Joint Rules and is designed to ensure that the component fixed income securities have sufficient publicly available information.

[27] 15 U.S.C. 78m and 78o(d).

[28] 15 U.S.C. 78c(a)(12).

[29] *See* Joint Rules, *supra* note 22, 71 FR at 30537.

[30] In its proposal, the Exchange stated its view that the minimum principal amount outstanding requirement of $100 million, coupled with the proposed concentration requirements, would reduce the likelihood that an ETF listed under the proposal would be readily susceptible to manipulation.

[31] *See* proposed Commentary .05 to Amex Rule 1000–AEMI and Commentary .04 to Amex Rule 1000A–AEMI.

the index value does not change during some or all of the period when trading is occurring on the Exchange, the last official calculated index value must remain available throughout Exchange trading hours.

Moreover, if a Fixed Income Index or Combination Index underlying an ETF is maintained by broker-dealer or fund advisor, the broker-dealer or fund advisor shall erect a ''firewall'' around the personnel who have access to information concerning changes and adjustments to the index. In addition, any advisory committee, supervisory board, or similar entity that advises a Reporting Authority or that makes decisions on index composition, methodology, and related matters, must implement and maintain, or be subject to, procedures designed to prevent the use and dissemination of material non-public information regarding the index.

F. Application of General Rules

Proposed Commentary .06 to Amex Rule 1000–AEMI and Commentary .05 to Amex Rule 1000A–AEMI set forth requirements governing any ETF based on a Fixed Income Index or Combination Index. These include initial shares outstanding, minimum price variation, listing fees, surveillance procedures, the application of PDR or IFS rules (as applicable), and the dissemination of the Intraday Indicative Value, which is an estimate of the value of a share of each ETF, updated at least every 15 seconds.

G. ETF Listing Criteria, Trading Rules, and Procedures

Under the Exchange's proposal, an ETF based on a Fixed Income Index or Combination Index would be subject to the listing criteria set out in Amex Rules 1002 and 1002A. Accordingly, an ETF's NAV must be calculated at least once each day and disseminated to all market participants at the same time.[32] Also, where the value of the underlying index or portfolio of securities on which the ETF is based is no longer calculated or available, or if the ETF chooses to substitute a new index or portfolio for the existing index or portfolio, the Exchange would commence delisting proceedings if the new index or portfolio does not meet the requirements of and listing standards set forth in Amex Rules 1000–AEMI and Rules 1001 *et seq.* or Amex Rules 1000A–AEMI and 1001A *et seq.*, as applicable. If an ETF chose to substitute an index that did not meet any of Amex's generic listing standards, approval by the Commission of a separate filing pursuant to Section 19(b)(2) of the Act to list and trade that ETF would be required.

An ETF based on a Fixed Income Index or Combination Index would be traded, in all respects, under the Exchange's existing trading rules and procedures that apply to ETFs generally, including with respect to delisting and trading halts.[33] In particular, Amex Rules 1002(b)(ii) and 1002A(b)(ii) provide that, if the Intraday Indicative Value or the index value applicable to that series of ETFs is not being disseminated as required, the Exchange may halt trading during the day in which the interruption to the dissemination of the Intraday Indicative Value or the index value occurs. If the interruption to the dissemination of the Intraday Indicative Value or the index value persists past the trading day in which it occurred, the Exchange would halt trading no later than the beginning of the trading day following the interruption.[34]

As noted above, if a broker-dealer is responsible for maintaining (or has a role in maintaining) the underlying index, such broker-dealer would be required to erect and maintain a ''firewall,'' in a form satisfactory to the Exchange, to prevent the flow of non-public information regarding the underlying index from the personnel involved in the development and maintenance of such index to others such as sales and trading personnel.

H. Surveillance

The Exchange represents that an ETF based on a Fixed Income Index or Combination Index would be covered under the Exchange's surveillance program for ETFs.[35] The Exchange will implement written surveillance procedures for an ETF based on a Fixed Income Index or a Combination Index.[36] The Exchange represents that its surveillance procedures are adequate to properly monitor the trading of ETFs listed pursuant to the proposed new listing standards. In addition, the Exchange also has a general policy prohibiting the distribution of material, non-public information by its employees.

III. Discussion and Commission Findings

After careful review, the Commission finds that the proposed rule change, as amended, is consistent with the Act and the rules and regulations thereunder applicable to a national securities exchange.[37] In particular, the Commission believes that the proposal is consistent with Section 6(b)(5) of the Act[38] in that it is designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, to foster cooperation and coordination with persons engaged in facilitating transactions in securities, to remove impediments to and perfect the mechanism of a free and open market and a national market system, and, in general, to protect investors and the public interest.

Currently, the Exchange must file a proposed rule change with the Commission pursuant to Section 19(b)(1) of the Act[39] and Rule 19b–4 thereunder[40] to list or trade any ETF based on Fixed Income Securities. The Exchange also must file a proposed rule change to list or trade an ETF based on a Fixed Income or Combination Index described in an exchange rule previously approved by the Commission as an underlying benchmark for a derivative security. Rule 19b–4(e), however, provides that the listing and trading of a new derivative securities product by an SRO will not be deemed a proposed rule change pursuant to Rule 19b–4(c)(1) if the Commission has approved, pursuant to Section 19(b) of the Act, the SRO's trading rules, procedures, and listing standards for the product class that would include the new derivative securities product, and the SRO has a surveillance program for the product class. The Exchange's proposed rules for the listing and trading of ETFs pursuant to Rule 19b–4(e) based on (1) certain indexes with components that include Fixed Income Securities or (2) indexes or portfolios described in exchange rules previously approved by the Commission as underlying benchmarks for derivative securities fulfill these requirements. Use of Rule 19b–4(e) by Amex to list and trade such ETFs should promote

[32] *See* Amex Rules 1002(a)(ii) and 1002A(a)(ii) (requiring that, before approving an ETF for listing, the Exchange will obtain a representation from the ETF issuer that the NAV per share will be calculated daily and made available to all market participants at the same time).

[33] *See* Amex Rules 1000–AEMI and 1001 through 1006 and Amex Rules 1000A–AEMI and 1001A through 1005A.

[34] If an ETF is traded on the Exchange pursuant to unlisted trading privileges, the Exchange would halt trading if the primary listing market halts trading in such ETF because the Intraday Indicative Value and/or the index value is not being disseminated. See Amex Rules 1002(b)(ii) and 1002A(b)(ii).

[35] *See* Amendment No. 2.

[36] *See* proposed Commentary .06(f) to Amex Rule 1000–AEMI and Commentary .05(f) to Amex Rule 1000A–AEMI.

[37] In approving this proposal, the Commission has considered its impact on efficiency, competition, and capital formation. See 15 U.S.C. 78c(f).

[38] 15 U.S.C. 78f(b)(5).

[39] 15 U.S.C. 78s(b)(1).

[40] 17 CFR 240.19b–4.

competition, reduce burdens on issuers and other market participants, and make such ETFs available to investors more quickly.[41]

The Commission has previously approved generic listing standards for ETFs based on indexes that consist of stocks listed on U.S. and non-U.S. exchanges, as well as for other index-based derivatives.[42] The Commission has also approved for listing and trading ETFs based on certain fixed income indexes and structured notes linked to a basket or index of Fixed Income Securities.[43] The Commission believes that adopting additional generic listing standards for ETFs based on Fixed Income and Combination Indexes should fulfill the intended objective of that rule by allowing those ETFs that satisfy the proposed generic listing standards to commence trading without a rule filing. Taken together, the Commission finds that the Amex proposal meets the requirements of Rule 19b–4(e). All products listed under the proposed generic listing standards will be subject to existing Amex rules that governing the trading of ETFs.

Proposed Commentary .04 to Amex Rule 1000–AEMI (for PDRs) and proposed Commentary .03 to Amex Rule 1000A–AEMI (for IFSs) establish the standards for the composition of a Fixed Income Index or Combination Index underlying an ETF. These requirements are designed, among other things, to require that components of an index or portfolio underlying the ETF are adequately capitalized and sufficiently liquid, and that no one security dominates the index. The Commission believes that these standards are reasonably designed to ensure that a substantial portion of any underlying index or portfolio consists of securities about which information is publicly available, and that when applied in conjunction with the other applicable listing requirements, will permit the listing and trading only of ETFs that are sufficiently broad-based in scope to minimize potential manipulation. The Commission further believes that the proposed listing standards are reasonably designed to preclude Amex from listing and trading ETFs that might be used as a surrogate for trading in unregistered securities.

The proposed generic listing standards also will permit Amex to list and trade an ETF if the Commission previously has approved an exchange rule that contemplates listing and trading a derivative security based on the same underlying index. Amex would be able to rely on that earlier approval order, provided that Amex complies with the commitments undertaken by the other SRO set forth in the prior order, including any surveillance-sharing arrangements.

The Commission believes that Amex's proposal is consistent with Section 11A(a)(1)(C)(iii) of the Act,[44] which sets forth Congress' finding that it is in the public interest and appropriate for the protection of investors and the maintenance of fair and orderly markets to assure the availability to brokers, dealers, and investors of information with respect to quotations for and transactions in securities. Under the Exchange's proposed listing standards, the underlying value of a Fixed Income Index is required to be widely disseminated by one or more major market data vendors at least once a day during the time when the corresponding ETF trades on the Exchange. Likewise, the underlying value of a Combination Index is required to be widely disseminated by one or more major market data vendors at least once every 15 seconds during the time when the corresponding ETF trades on the Exchange, provided that, with respect to the fixed income components of the Combination Index, the impact on the index is required to be updated only once each day.

Furthermore, the Commission believes that the proposed rules are reasonably designed to promote fair disclosure of information that may be necessary to price an ETF appropriately. If a Fixed Income Index or Combination Index underlying such an ETF is maintained by a broker-dealer or fund advisor, that entity must erect a firewall around the personnel who have access to information concerning changes and adjustments to the index. Any advisory committee, supervisory board, or similar entity that advises a Reporting Authority or that makes decisions on index composition, methodology, or related matters must implement and maintain, or be subject to, procedures designed to prevent the use and dissemination of material non-public information regarding the index. The Commission also notes that existing Amex Rules 1002(a)(ii) and 1002A(a)(ii), which would apply to an ETF listed and traded pursuant to this proposal, require that, before approving an ETF for listing, the Exchange will obtain a representation from the ETF issuer that the NAV per share will be calculated daily and made available to all market participants at the same time.

The Commission also believes that the Exchange's trading halt rules are reasonably designed to prevent trading in an ETF when transparency cannot be assured. Amex Rules 1002(b)(ii) and 1002A(b)(ii) provide that, if the Intraday Indicative Value or the index value applicable to an ETF is not disseminated as required, the Exchange may halt trading during the day in which the interruption occurs. If the interruption continues, the Exchange will halt trading no later than the beginning of the next trading day.[45] Also, the Exchange will commence delisting proceedings in the event that the value of the underlying index is no longer calculated and widely disseminated on at least a 15-second basis (for Combination Indexes) or at least once a day (for Fixed Income Indexes).

The Exchange will implement written surveillance procedures for ETFs based on a Fixed Income Indexes or Combination Indexes.[46] In approving this proposal, the Commission has relied on the Exchange's representation that its surveillance procedures are adequate to properly monitor the trading of ETFs listed pursuant to this proposal. This approval order is conditioned on the continuing accuracy of that representation.

Acceleration

The Commission finds good cause to approve the proposal, as amended, prior to the thirtieth day after the amended proposal was published for comment in the **Federal Register**. The Commission believes that accelerating approval of the proposed rule change will expedite the listing and trading of additional ETFs based on Fixed Income and Combination Indexes by the Exchange, subject to consistent and reasonable standards. The Commission also notes that no comments were received during the abbreviated comment period, and

[41] The Commission notes that failure of a particular ETF to satisfy the Exchange's generic listing standards does not preclude the Exchange from submitting a separate proposal to list and trade such ETF.

[42] *See* notes 12–14 *supra*. The Commission notes that such listing standards permit an exchange to list new derivative securities pursuant to Rule 19b–4(e) under the Act based on portfolios or indexes that underlie securities described in other previously approved rules, subject to the condition that all of the standards set forth in the approval order are satisfied by the exchange employing generic listing standards.

[43] *See* notes 15–16 supra.

[44] 15 U.S.C. 78k–1(a)(1)(C)(iii).

[45] If an ETF is traded on the Exchange pursuant to unlisted trading privileges, the Exchange would halt trading if the primary listing market halts trading in such ETF because the Intraday Indicative Value and/or the index value is not being disseminated. See Amex Rules 1002(b)(ii) and 1002A(b)(ii).

[46] *See* proposed Commentary .06(f) to Amex Rule 1000–AEMI and Commentary .05(f) to Amex Rule 1000A–AEMI.

that Amendments No. 2 and 3 do not make any substantial changes to the proposal. Thus, the Commission finds good cause, consistent with Section 19(b)(2) of the Act,[47] to grant accelerated approval of the proposed rule change, as amended.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments regarding Amendments No. 2 and 3, including whether Amendments No. 2 and 3 are consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an e-mail to *rule-comments@sec.gov*. Please include File Number SR–Amex–2006–118 on the subject line.

Paper Comments

- Send paper comments in triplicate to Nancy M. Morris, Secretary, Securities and Exchange Commission, Station Place, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–Amex–2006–118. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for inspection and copying in the Commission's Public Reference Room. Copies of such filing also will be available for inspection and copying at the principal office of Amex. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–Amex–2006–118 and should be submitted on or before April 5, 2007.

[47] 15 U.S.C. 78s(b)(2).

V. Conclusion

It is therefore ordered, pursuant to Section 19(b)(2) of the Act,[48] that the proposed rule change (SR–Amex–2006–118), as amended, be, and hereby is, approved on an accelerated basis.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[49]

Florence E. Harmon,

Deputy Secretary.

[FR Doc. E7–4747 Filed 3–14–07; 8:45 am]

BILLING CODE 8010–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–55425; File No. SR–CBOE–2006–73]

Self-Regulatory Organizations; Chicago Board Options Exchange, Incorporated; Notice of Filing of Amendment No. 2 and Order Granting Accelerated Approval of Proposed Rule Change as amended, to Amend Certain of its Rules to Provide for the Listing and Trading of Options on the CBOE Russell 2000 Volatility Index[sm] (''RVX[sm]'')

March 8, 2007.

I. Introduction

On August 31, 2006, the Chicago Board Options Exchange, Incorporated (''CBOE'' or ''Exchange'') filed with the Securities and Exchange Commission (''Commission'') a proposed rule change, pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'')[1] and Rule 19b–4 thereunder,[2] to amend certain of its rules to provide for the listing and trading of options on the CBOE Russell 2000 Volatility Index[sm] (''RVX[sm]''). On October 20, 2006, CBOE filed Amendment No. 1 to the proposed rule change. The proposed rule change, as modified by Amendment No. 1, was published for comment in the **Federal Register** on October 30, 2006.[3] The Commission received no comments on the proposal. On February 26, 2007, CBOE filed Amendment No. 2 to the proposed rule change.[4] This order provides notice of Amendment No. 2 to the proposed rule change and approves the proposed rule change as amended.

[48] 15 U.S.C. 78s(b)(2).

[49] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] *See* Securities Exchange Act Release No. 54643 (October 23, 2006), 71 FR 63367 (''Notice'').

[4] In Amendment No. 2, the Exchange represented that CBOE Futures Exchange, LLC (''CFE'') does not currently list and trade RVX futures. The Exchange further represented that it will not list for trading RVX options until RVX futures have begun trading on CFE.

II. Description of the Proposal

The Exchange seeks to list and trade cash-settled, European-style options on the RVX. The index is calculated using real-time Russell 2000 Index (''RUT'') option bid/ask quotes. RVX uses nearby and second nearby RUT options with at least 8 days left to expiration and then weights them to yield a constant, 30-day measure of the expected volatility of the RUT.

For each contract month, CBOE will determine the at-the-money strike price. It will then select the at-the-money and out-of-the money series with non-zero bid prices and determine the midpoint of the bid-ask quote for each of these series. The midpoint quote of each series is then weighted so that the further away that series is from the at-the-money strike, the less weight that is accorded to the quote. Then, to compute the index level, CBOE will calculate a volatility measure for the nearby options and then for the second nearby options. This is done using the weighted mid-point of the prevailing bid-ask quotes for all included option series with the same expiration date. These volatility measures are then interpolated to arrive at a single, constant 30-day measure of volatility.[5]

CBOE will compute the index on a real-time basis throughout each trading day, from 8:30 a.m. until 3:15 p.m. CST. Volatility index levels will be calculated by CBOE and disseminated at 15-second intervals to market information vendors via the Options Price Reporting Authority (''OPRA'').

Because of the generally limited range in which RVX has fluctuated, the Exchange proposes to list series at $1.00 or greater strike price intervals for each expiration on up to 5 RVX option series above and 5 RVX option series below the current index level. Additional series at $1.00 or greater strike price intervals could be listed for each expiration as the current index level of RVX moves from the exercise price of the RVX options series that already have been opened for trading on the Exchange in order to maintain at least 5 RVX option series above and 5 RVX option series below the current index level.

[5] The Exchange represented in its filing that the RVX is calculated in the same manner as other volatility indexes (*e.g.,* the CBOE Volatility Index (''VIX'')), upon which options have been based and previously approved by the Commission. A more detailed explanation of the method used to calculate VIX may be found on CBOE's Web site at the following internet address: *http://www.cboe.com/micro/vix/vixwhite.pdf.*

Additionally, the Exchange proposes that it would not list series with $1.00 intervals within $0.50 of an existing $2.50 strike price with the same expiration month (*e.g.,* if there is an existing $12.50 strike, the Exchange would not list a $12.00 or $13.00 strike). The interval between strike prices for RVX long-term option series (''LEAPs(r)'') will continue to be no less than $2.50.

III. Discussion

After careful review, the Commission finds that CBOE's proposal to permit trading in options based on the RVX is consistent with the requirements of the Act and the rules and regulations thereunder applicable to a national securities exchange [6] and, in particular, the requirements of Section 6 of the Act [7] and the rules and regulations thereunder. The Commission believes that CBOE's proposal gives options investors the ability to make an additional investment choice in a manner consistent with the requirements of Section 6(b)(5) of the Act.[8] The Commission further believes that trading options on this volatility index provides investors with an important trading and hedging mechanism.

The Commission finds that it is consistent with the Act for CBOE to apply its rules for trading of broad-based index options to RVX. The Commission believes that because this volatility index is composed of options on an index which the Commission has previously determined is appropriate to treat as broad-based for purposes of CBOE's rules,[9] it is appropriate to apply to the RVX options the position limits, exercise limits and margin requirements that apply to CBOE's component index options.

The Commission also notes CBOE's representation that it has adequate surveillance procedures in place to monitor for manipulation of the RVX options. In addition, the Commission notes that the Exchange will use the same surveillance procedures currently utilized for each of the Exchange's other index options to monitor trading in options on the RVX and that CBOE believes that these surveillance procedures are adequate to monitor the trading of options on the RVX. For surveillance purposes, the Exchange will have complete access to information regarding trading activity in the pertinent underlying securities.

As explained by CBOE, the RVX fluctuates in a narrow range, and the Commission believes that the implementation of $1 strike price intervals in the RVX option product, within the parameters detailed in CBOE's proposal, is appropriate. The Commission also finds that CBOE's trading rules and other product specifications are consistent with the Act. Because the exercise of these options will be cash-settled, RVX options will be A.M.-settled on the business day following expiration, in a manner that will deter manipulation.

The Commission also notes CBOE's representations that it possesses the necessary systems capacity to support new series that would result from the introduction of RVX options and that CBOE also has been informed that OPRA has the capacity to support such new series.

The Commission finds good cause to approve the proposed rule change, as modified by Amendment Nos. 1 and 2 before the 30th day after the date of publication of notice of filing of Amendment No. 2 in the **Federal Register**. In Amendment No. 2, the Exchange represented that CBOE Futures Exchange, LLC (''CFE'') does not currently list and trade RVX futures and that the Exchange will not list for trading RVX options until RVX futures have begun trading on CFE. The Commission believes that this clarifying language is necessary because the Exchange plans to use RVX futures prices as a proxy for ''implied forward'' RVX levels.[10]

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change as amended is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an e-mail to *rule-comments@sec.gov.* Please include File Number SR–CBOE–2006–73 on the subject line.

Paper Comments

- Send paper comments in triplicate to Nancy M. Morris, Secretary, Securities and Exchange Commission, Station Place, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–CBOE–2006–73. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for inspection and copying in the Commission's Public Reference Room. Copies of such filing also will be available for inspection and copying at the principal office of the Exchange. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–CBOE–2006–73 and should be submitted on or before April 5, 2007.

V. Conclusion

It is therefore ordered, pursuant to Section 19(b)(2) of the Act,[11] that the proposed rule change (SR–CBOE–2006–73), as amended, be, and hereby is, approved on an accelerated basis.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[12]

Nancy M. Morris,

Secretary.

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[6] In approving this proposed rule change, the Commission has considered the proposed rule's impact on efficiency, competition, and capital formation. 15 U.S.C. 78c(f).

[7] 15 U.S.C. 78f.

[8] 15 U.S.C. 78f(b)(5).

[9] *See* Securities Exchange Act Release No. 31382 (October 30, 1992), 57 FR 52802 (November 5, 1992) (SR–CBOE–92–02).

[10] *See* Notice *supra* note 3.

[11] 15 U.S.C. 78s(b)(2).

[12] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–55426; File No. SR–ISE–2007–01]

Self-Regulatory Organizations; International Securities Exchange, LLC; Order Approving a Proposed Rule Change Relating to Rule 2113 (Long and Short Sales)

March 8, 2007.

On January 5, 2007, pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (the ''Act''),[1] and Rule 19b–4 thereunder,[2] the International Securities Exchange, LLC (the ''Exchange'' or the ''ISE'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change relating to NASD Rule 2113 (Long and Short Sales). The proposed rule change was published for comment in the **Federal Register** on February 5, 2007.[3] The Commission received no comments regarding this proposal. This order approves the rule change.

Discussion and Commission Findings

The Exchange proposes to amend ISE Rule 2113 (Long and Short Sales) to conform its language to Rule 10a–1(a)(1)(i) promulgated under the Act. Specifically, Rule 2113 (Long and Short Sales) currently provides that the Exchange will not execute a short sale order below the price at which the last sale was effected on the Exchange. The Exchange proposes to amend ISE Rule 2113 to conform its language to Rule 10a–1(a)(1)(i) promulgated under the Act, whereby the Exchange will not execute a short sale order below the price at which the last sale was reported pursuant to an effective transaction reporting plan, as defined in Rule 242.600 under the Act.

The Commission finds that the proposed rule change is consistent with the requirements of the Act and the rules and regulations thereunder applicable to a national securities exchange, and in particular Section 6(b)(5) of the Act [4] which requires that the rules of an exchange be designed to promote just and equitable principles of trade, serve to remove impediments to and perfect the mechanism for a free and open market and a national market system, and, in general, to protect investors and the public interest.[5]

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] *See* Securities Exchange Act Release No. 55191 (January 29, 2007), 72 FR 5305 (February 5, 2007).

[4] 15 U.S.C. 78f(b)(5).

[5] In approving this proposed rule change, the Commission notes that it has considered the proposed rule's impact on efficiency, competition, and capital formation. 15 U.S.C. 78c(f).

It is therefore ordered, pursuant to Section 19(b)(2) of the Act, that the proposed rule change (SR–ISE–2007–01) be, and it hereby is, approved.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[6]

Florence E. Harmon,

Deputy Secretary.

[FR Doc. E7–4691 Filed 3–14–07; 8:45 am]

BILLING CODE 8010–01–P

[6] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–55423; File No. SR–NYSEArca–2007–21]

Self-Regulatory Organizations; NYSE Arca, Inc.; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Relating to an Exemption from Certain of the Exchange's Shareholder Approval Requirements for Limited Partnerships

March 8, 2007.

Pursuant to Section 19(b)(1) [1] of the Securities Exchange Act of 1934 (the ''Act'') [2] and Rule 19b–4 thereunder,[3] notice is hereby given that on February 23, 2007, NYSE Arca, Inc. (the ''Exchange''), through its wholly owned subsidiary, NYSE Arca Equities, Inc. (''NYSE Arca Equities''), filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I and II below, which Items have been substantially prepared by Exchange. The Exchange has designated this proposal as non-controversial under Section 19(b)(3)(A)(iii) of the Act [4] and Rule 19b–4(f)(6) thereunder,[5] which renders the proposed rule change effective upon filing with the Commission. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

NYSE Arca is proposing to exempt limited partnerships (''LPs'') from the obligations to obtain shareholder approval for the issuance of common stock and related securities in the circumstances set forth in subsections (8) through (11) of NYSE Arca Equities Rule 5.3(d). The text of this proposed rule change is available on the Exchange's Web site (*http://www.nyse.com/RegulationFrameset.html?displayPage=http://www.nysearca.com/nysearca_reg/prf.asp),* at the Exchange's Office of the Secretary, and at the Commission's Public Reference Room.

[1] 15 U.S.C.78s(b)(1).

[2] 15 U.S.C. 78a.

[3] 17 CFR 240.19b–4

[4] 15 U.S.C. 78s(b)(3)(A).

[5] 17 CFR 240.19b–4(f)(6).

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of and basis for the proposed rule changes and discussed any comments it received regarding the proposal. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

NYSE Arca is proposing to exempt limited partnerships (''LPs'') from the obligations to obtain shareholder approval for the issuance of common stock and related securities in the circumstances set forth in subsections (8) through (11) of NYSE Arca Equities Rule 5.3(d).[6] The proposed amendment does not affect investors in any currently listed company, as there are currently no LPs listed on the Exchange.

Subsections (8) through (11) of NYSE Arca Equities Rule 5.3(d) require listed issuers to obtain shareholder approval prior to the issuance of designated securities in the following situations:

• Issuances that will result in a change of control of the issuer.

• In connection with the acquisition of the stock or assets of another company, shareholder approval is needed in the following circumstances:

• If any director, officer, or substantial shareholder of the listed company has a 5% or greater interest (or such persons collectively have a 10% or greater interest), directly or indirectly, in the company or assets to be acquired or in the consideration to be paid in the transaction (or series of related

[6] This filing does not in any way limit the applicability of the provisions of NYSE Arca Equities Rule 5.2(i) to limited partnership rollups (as defined in Section 14(h) of the Securities Exchange Act of 1934) or the continued applicability of any other rule that is currently applicable to LPs.

transactions) and the present or potential issuance of common stock, or securities convertible into or exercisable for common stock, could result in an increase in outstanding common shares or voting power of 5% or more; or

• Where the present or potential issuance of common stock, or securities convertible into or exercisable for common stock (other than in a public offering for cash), could result in an increase in outstanding common shares of 20% or more or could represent 20% or more of the voting power outstanding before the issuance of such stock or securities.

• In connection with a transaction other than a public offering involving:

• The sale or issuance by the company of common stock (or securities convertible into or exercisable for common stock) at a price less than the greater of book or market value, which together with sales by officers, directors or principal shareholders of the company equals 20% or more of presently outstanding common stock, or 20% or more of the presently outstanding voting power; or

• The sale or issuance by the company of common stock (or securities convertible into or exercisable for common stock) equal to 20% or more of presently outstanding stock or voting power for less than the greater of book or market value of the stock.

The policy underlying these requirements is that shareholders should have the right to vote on any issuance of common stock that is materially dilutive of either their voting or economic interest in the company. Nasdaq has essentially identical shareholder approval requirements to those of the NYSE Arca. However, Nasdaq exempts LPs from those requirements,[7] which has placed NYSE Arca at a significant disadvantage in competing with Nasdaq for initial public offerings and transfers of LPs. To be treated as a partnership for federal tax purposes, an LP must ensure that 90% of its income is derived from ''qualified sources,'' which generally refers only to income derived from natural resource-related activities. Most listed LPs are engaged in energy-related businesses. The typical business model of LPs in the energy industry is to use their capital to acquire assets (e.g., pipelines) that produce predictable revenue streams and to commit in their partnership agreements to distribute most of their profits to the LP's unit holders. These LPs acquire assets frequently on an opportunistic basis and pay for them by issuing additional LP units. The ability of an LP listed on Nasdaq to issue additional LP units without the expense and uncertainty of obtaining shareholder approval provides Nasdaq with a significant advantage over NYSE Arca in attracting and retaining listings of LPs.

The Exchange believes that an analysis of the policies regarding voting and economic dilution underpinning its shareholder approval requirements demonstrates that it is appropriate to exempt LPs from their application. Listed LPs generally provide very limited voting rights to their unit holders. Typically, control of the LP resides with the general partner (''GP'') and the LP's board is that of the GP. The owner of the GP appoints the board and the common unit holders of the LP have no voting rights with respect to the election of directors. LP partnership agreements generally provide that LP unit holders can vote only on a merger or dissolution of the LP or on any amendment to the partnership agreement that is adverse to their interests. As such, investors who buy LP units have no expectation that they will be able to vote and, therefore, the policy that shareholders should be able to vote on any stock issuances that are materially dilutive of their voting power is of less relevance to LPs than to regular corporations. Furthermore, because LP unit holders generally do not have the right to elect directors, most LPs do not hold annual meetings. Therefore, it would not be possible for an LP to arrange for shareholder approval to be obtained in conjunction with an annual meeting, as would be possible for a regular company. Rather, an LP would have to call a special meeting every time it needed approval of an issuance pursuant to the shareholder approval rules.

The Exchange also believes that the economic dilution concerns underpinning the shareholder approval rules are also less relevant in the case of LPs. Listed LPs typically are required under their partnership agreements to distribute almost all of their earnings to their unit holders and specify a minimum quarterly distribution that the LP is required to make. As such, LPs will only invest in new assets if they know that those assets will be sufficiently accretive to earnings to pay the minimum quarterly distribution required for the additional units that are sold to raise the capital to pay for those assets. A failure to pay the minimum quarterly distribution, or a reduction in the actual distribution level historically paid, would likely, in the Exchange's view, have a negative effect on the trading price of a listed LP, imposing a market discipline on management to ensure that any additional issuances will not be economically dilutive.

2. Statutory Basis

The proposed rule change is consistent with Section 6(b)[8] of the Act in general, and furthers the objectives of Section 6(b)(5)[9] in particular in that it is designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, to foster cooperation and coordination with persons engaged in facilitating transactions in securities, and to remove impediments to and perfect the mechanisms of a free and open market and a national market system. The Exchange believes that the proposed rule change will increase competition among listing markets and will remove a competitive disadvantage the Exchange currently has vis a vis Nasdaq and is therefore designed to perfect the mechanism of a free and open market.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition that is not necessary or appropriate in furtherance of the purpose of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants or Others

Written comments on the proposed rule change were neither solicited nor received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Because the proposed rule change does not: (1) Significantly affect the protection of investors or the public interest; (2) impose any significant burden on competition; and (3) become operative for 30 days after the date of

[7] *See* Nasdaq Marketplace Rule 4360 (''Qualitative Listing Requirements for Nasdaq Issuers That Are Limited Partnerships''), which does not include the shareholder approval requirements found in Nasdaq Marketplace Rule 4350 (''Qualitative Listing Requirements for Nasdaq Issuers That Are Not Limited Partnerships''). *See also* Exchange Act Release No. 30811 (June 15, 1992); 57 FR 28542 (June 25, 1992) (SR–NASD–91–58) (approving the NASD's adoption of non-quantitative listing standards for partnerships, which did not include shareholder approval requirements). *See also* Exchange Act Release No. 34533 (August 15, 1994); 59 FR 43147 (August 22, 1994) (SR–NASD–93–3) (approving the NASD's adoption of the predecessor rule to Rule 4360, which also did not include shareholder approval requirements for listed limited partnerships).

[8] 15 U.S.C. 78f(b).

[9] 9 15 U.S.C. 78f(b)(5).

the filing, or such shorter time as the Commission may designate if consistent with the protection of investors and the public interest, the proposed rule change has become effective pursuant to Section 19(b)(3)(A) of the Act [10] and Rule 19b–4(f)(6) thereunder.[11]

At any time within 60 days of the filing of the proposed rule change, the Commission may summarily abrogate such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

A proposed rule change normally may not become operative prior to 30 days after the date of filing.[12] However, Rule 19b–4(f)(iii) [13] permits the Commission to designate a shorter time if such action is consistent with the protection of investors and the public interest. The Exchange has requested that the Commission waive the 30-day operative delay. The Commission believes that waiver of the 30 day operative delay is consistent with the protection of investors and the public interest.[14] The Commission notes that because there are no LPs presently listed on the NYSE Arca, there are no shareholders retroactively or currently impacted by the proposed rule change. Further, the proposed rule change will eliminate the competitive disadvantage to the NYSE Arca resulting from the present disparity in shareholder approval requirements between the NYSE Arca's and Nasdaq's treatment of LPs, while still retaining for NYSE Arca-listed LPs the provisions of the Exchange's rules relating to shareholder approval of equity compensation plans.[15]

[10] 15 U.S.C. 78s(b)(3)(A).

[11] 17 CFR 240.19b–4(f)(6).

[12] 17 CFR 240.19b–4(f)(6)(iii). Rule 19b–4(f)(6)(iii) requires hat a self-regulatory organization submit to the Commission written notice of its intent to file the proposed rule change, along with a brief description and text of the proposed rule change, at least five business days prior to the date of filing of the proposed rule change, or such shorter time as designated by the Commission. The Exchange satisfied this requirement.

[13] 17 CFR 240.19b–4(f)(6)(iii).

[14] For purposes only of waiving the 30-day operative delay, the Commission has considered the proposed rule's on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f).

[15] *See* NYSE Arca Rule 5.3(d)(1)–(7) (setting forth the Exchange's rules with respect to shareholder approval of equity compensation plans). The proposed rule change would only eliminate the application of subparagraphs (8) through (11) to Rule 5.3(d) to limited partnerships. The Commission believes that it is desirable for the Exchange to have retained the requirements pertaining to shareholder approval of equity compensation plans for NYSEArca–listed limited partnerships.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views and arguments concerning the foregoing, including whether the proposed rule change, as amended, is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send e-mail to *rule-comments@sec.gov.* Please include File Number SR–NYSEArca–2007–21 on the subject line.

Paper Comments

- Send paper comments in triplicate to Nancy M. Morris, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to file Number SR–NYSEArca–2007–21. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro/shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for inspection and copying in the Commission's Public Reference Room. Copies of such filings will also be available for inspection and copying at the principal office of the Exchange. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File number SR–NYSEArca–2007–21 and should be submitted by April 5, 2007.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[16]

Florence E. Harmon,

Deputy Secretary.

[FR Doc. E7–4692 Filed 3–14–07; 8:45 am]

BILLING CODE 8010–01–P

[16] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–55424; File No. SR–Phlx–2006–63]

Self-Regulatory Organizations; Philadelphia Stock Exchange, Inc.; Notice of Filing of Amendment No. 3 to the Proposed Rule Change, and Order Granting Accelerated Approval of Proposed Rule Change as Amended, Relating to a Philadelphia Board of Trade Enterprise License Fee for Dissemination of Certain Market Data

March 8, 2007.

I. Introduction

On September 28, 2006, the Philadelphia Stock Exchange, Inc. (''Phlx'' or ''Exchange'') filed with the Securities and Exchange Commission (''Commission''), pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'') [1] and Rule 19b–4 thereunder,[2] a proposal to add an Enterprise License Fee of $10,000 per year or $850 per month that would be assessed by the Exchange's wholly owned subsidiary, the Philadelphia Board of Trade (''PBOT''), on eligible market data vendors or subvendors (collectively ''Vendors'') for certain index values that subscribers receive over PBOT's Market Data Distribution Network (''MDDN''). The Phlx filed Amendment No. 1 to the proposed rule change on November 1, 2006 and filed Amendment No. 2 on December 20, 2006. The proposed rule change, as amended, was published for comment in the **Federal Register** on December 28, 2006.[3] The Phlx filed Amendment No. 3 to the proposed rule change on March 2, 2007.[4] The Commission received no comments regarding the proposal. The Commission hereby issues notice of the filing of Amendment No. 3 and simultaneously grants accelerated approval to the proposed rule change as amended.

II. Description of the Proposal

The Phlx proposes to add an Enterprise License Fee for eligible Vendors of market data disseminated

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] *See* Securities Exchange Act Release No. 54978 (December 20, 2006), 71 FR 78254.

[4] In Amendment No. 3, Phlx clarified (1) in its fee schedule that a retail broker dealer is conducting a material portion of its business via one or more Internet Web sites if at least 20% of the broker-dealer's business were conducted via the Internet; and (2) that the current and closing index values underlying all of Phlx's proprietary indexes are being disseminated through PBOT.

over PBOT's MDDN.[5] The Phlx has licensed the current and closing index values underlying all of the Phlx's proprietary indexes to PBOT for the purpose of selling, reproducing, and distributing the index values over PBOT's MDDN (''Market Data''). On each trading day, the Exchange or its third party designee calculates and makes available to PBOT a real-time index value every 15 seconds and a closing index value at the end of each trading day. In exchange for subscriber fees paid to PBOT, market data vendors are allowed to widely disseminate all the values of Phlx's proprietary indexes to their subscribers.[6]

As approved by the Commission, PBOT charges the following subscriber fees to Vendors of Market Data for all the values of Phlx's proprietary indexes disseminated by PBOT's MDDN: [7] a monthly fee of: (a) $1.00 per ''Device,'' [8] that is used by Vendors and their subscribers to receive and re-transmit Market Data on a real-time basis (''device fee''), and (b) $.0025 per request for snapshot data,[9] which is essentially Market Data that is refreshed no more frequently than once every 60 seconds, or $1,500 per month for unlimited snapshot data requests (''snapshot fee'').[10] All market data vendors which provide market data to 200,000 or more Devices in any month qualify for a 15% Administrative Fee credit for that month, to be deducted from the monthly Subscriber Fees that they collect and are obligated to pay PBOT under the Vendor/Subvendor Agreement.

The Exchange proposes to add an Enterprise License Fee of $10,000 per year or $850 per month that would be available to eligible Vendors as an alternative to the device fee or snapshot fee.[11] A Vendor is eligible for the Enterprise License Fee if it is a firm acting as a retail broker-dealer conducting a material portion of its business via one or more proprietary Internet Web sites by which the firm distributes Market Data to predominately non-professional Market Data users with whom the firm has a brokerage relationship (''Eligible Firm'').[12] An Eligible Firm may also distribute Market Data to professional users with whom such firm has a brokerage relationship, provided such Market Data distribution is predominantly to non-professional users.[13] As stated in the proposed fee schedule, the Eligible Firm's Market Data distribution to professional users cannot exceed 10%.[14] The 15% Administrative Fee credit discount also applies to the Enterprise License Fee.

To be eligible for the Enterprise License Fee, an Eligible Firm must certify to PBOT that it qualifies for the Enterprise License Fee, including that market distribution is predominantly to non-professional users, and must immediately notify PBOT if it can no longer certify its qualification.[15]

III. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change, as amended, is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

• Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or

• Send an e-mail to *rule-comments@sec.gov*. Please include File No. SR–Phlx–2006–63 on the subject line.

Paper Comments

• Send paper comments in triplicate to Nancy M. Morris, Secretary, Securities and Exchange Commission, Station Place, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–Phlx–2006–63. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for inspection and copying in the Commission's Public Reference Room. Copies of such filing also will be available for inspection and copying at the principal office of the Phlx.

All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–Phlx–2006–63 and should be submitted on or before April 5, 2007.

IV. Discussion

After careful consideration, the Commission finds that the proposed rule change is consistent with the requirements of the Act and the rules and regulations thereunder applicable to

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[5] The MDDN is an internet protocol multicast network developed by PBOT and SAVVIS Communications.

[6] PBOT has contracted with one or more major Market Data Vendors to receive real-time and closing index values over the MDDN and promptly redistribute such values.

[7] *See* Securities Exchange Act Release No. 53790 (May 11, 2006), 71 FR 28738 (May 17, 2006) (''Original Approval Order''). The subscriber fees are set out in agreements that PBOT executed with various market data vendors for the right to receive, store, and retransmit the current and closing index values transmitted over the MDDN.

[8] The agreements provide that ''Device'' shall mean, in case of each Subscriber and in such Subscriber's discretion, either any Terminal or any End User. A Subscriber's Device may be exclusively Terminals, exclusively End Users or a combination of Terminals or End Users and shall be reported in a manner that is consistent with the way the Vendor identifies such Subscriber's access to Vendor's data. An ''End User'' is defined as an individual authorized or allowed by a Vendor to access and display real-time market data that is distributed by PBOT over the MDDN; and a ''Terminal'' is any type of equipment (fixed or portable) that accesses and displays such market data.

[9] *See* Securities Exchange Act Release No. 55111 (January 16, 2007), 72 FR 3188 (January 24, 2007) (increasing the snapshot fee to $.0025 per request).

[10] The index values may also be made available by Vendors on a delayed basis (*i.e.*, no sooner than twenty minutes following receipt of the data by vendors) at no charge.

[11] A firm that qualifies for the Enterprise License Fee may instead choose to pay the device fee and/or the snapshot fee as appropriate.

[12] To be eligible for the Enterprise License Fee, the Exchange's fee schedule states that an Eligible Firm will be considered to conduct a material portion of its business via one or more Internet Web sites if at least twenty percent (20%) of the firm's business were conducted via the Internet.

[13] A non-professional user is defined in the fee schedule as any natural person who is not: (a) registered or qualified in any capacity with the Commission, the Commodities Futures Trading Commission, any state securities agency, any securities exchange or association, or any commodities or futures contract market or association; (b) engaged as an ''investment advisor'' as that term is defined in Section 202(11) of the Investment Advisors Act of 1940, 15 U.S.C. 80b–2(11), (whether or not registered or qualified under that Act); nor, (c) employed by a bank or other organization exempt from registration under federal or state securities laws to perform functions that would require registration or qualification if such functions were performed for an organization not so exempt.

[14] As an example, if data recipient ABC Corp. has 100 customers that receive PBOT Market Data of which 10 are professional users and 90 are retail (non-professional) users the Enterprise License Fee would be available to the firm because 10 professional users/100 total users = 10%.

[15] A firm that has entered into an agreement with PBOT to receive Market Data over the MDDN but is not qualified for the Enterprise License Fee may pay the device fee and/or the snapshot fee as appropriate.

a national securities exchange [16] and, in particular, the requirements of Section 6 of the Act.[17] Specifically, the Commission finds that the proposed rule change is consistent with Section 6(b)(5) of the Act,[18] which requires, among other things, that the rules of a national securities exchange be designed to promote just and equitable principles of trade, to remove impediments to and perfect the mechanism of a free and open market and a national market system, and, in general, to protect investors and the public interest.

The Commission believes that the reduced alternate fee structure available through the Enterprise License Fee to eligible market data recipients should help to encourage a wider distribution of market data, especially to non-professional customers. The Commission notes that other industry organizations have similar fee structures which make various market data available to non-professional subscribers for a discounted fee relative to professional subscribers. For example, the Nasdaq Stock Market, Inc. (''Nasdaq'') has fees schedules that are higher for professional or corporate subscribers than for non-professional subscribers for UTP Level 1 fees, TotalView fees, and Nasdaq MAX fees.[19] The Options Price Reporting Authority (''OPRA''), a national market system plan, also offers a reduced fee to nonprofessional subscribers, which is not available to professional options data subscribers.[20]

The Commission also believes that Phlx's eligibility standards in determining the type of retail broker-dealers who can use the new Enterprise License Fee appears to be reasonably related to its purpose of providing a discount to those retail broker-dealers who have primarily a proprietary Internet based business to non-professional users.[21] As noted above, eligible firms are also free to pay, as an alternative, the device fee or snapshot fee should they so choose.

Based on the above, the Commission believes that the proposal is consistent with Section 6(b)(4) of the Act,[22] in that the proposed rule change provides for the equitable allocation of reasonable dues, fees, and other charges among the Exchange's members and issuers and other persons using its facilities. The Commission also continues to believe that PBOT's MDDN fee structure is consistent with Rule 603 under the Act [23] regarding the distribution, consolidation, and display of information with respect to quotations for and transactions in NMS stocks.

The Commission finds good cause for approving Amendment No. 3 to the proposed rule change prior to the thirtieth day after the notice is published for comment in the **Federal Register** pursuant to Section 19(b)(2) of the Act.[24] Amendment No. 3 clarifies the Exchange's proposal and does not raise any new regulatory issues. Further, the materiality standard in the Eligible Firm definition drafted into the fee schedule pursuant to Amendment No. 3 was the same standard published for comment with the filing and no comments were received. Finally, the Commission believes that it is appropriate to accelerate approval of the proposed rule change so that the Exchange can immediately provide the discounted fee to eligible firms that will disseminate the index values of Phlx's proprietary index options. Accordingly, the Commission finds good cause to approve Amendment No. 3 prior to the thirtieth day after the notice is published for comment in the **Federal Register**.

V. Conclusion

It is therefore ordered, pursuant to Section 19(b)(2) of the Act,[25] that the proposed rule change (SR–Phlx–2006–63), as amended, be, and it hereby is, approved on an accelerated basis.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[26]

Florence E. Harmon,

Deputy Secretary.

[FR Doc. E7–4722 Filed 3–14–07; 8:45 am]

BILLING CODE 8010–01–P

[16] In approving this proposed rule change, the Commission has considered the proposed rule's impact on efficiency, competition, and capital formation. 15 U.S.C. 78c(f).

[17] 15 U.S.C. 78f.

[18] 15 U.S.C. 78f(b)(5).

[19] Nasdaq offers a TotalView Non-Professional Enterprise Fee License to qualified firms that distribute TotalView to their non-professional users with whom they have a professional relationship. A description of Nasdaq market data fees is available at *http://www.nasdaqtrader.com/trader/mds/nasdaqother/pricing.stm* (last visited on January 17, 2007).

[20] A description of OPRA market data fees is available at *http://www.opradata.com/pdf/prof_pub_fee_schd_revised.pdf* (last visited on January 17, 2007).

[21] *See supra* notes 12–15 and accompanying text for eligibility standards for the Enterprise License Fee.

[22] 15 U.S.C. 78f(b)(4).

[23] 17 CFR 242.603.

[24] 15 U.S.C. 78s(b)(2).

[25] 15 U.S.C. 78s(b)(2).

[26] 17 CFR 200.30–3(a)(12).

SOCIAL SECURITY ADMINISTRATION

Agency Information Collection Activities: Proposed Request and Comment Request

The Social Security Administration (SSA) publishes a list of information collection packages that will require clearance by the Office of Management and Budget (OMB) in compliance with Pub. L. 104–13, the Paperwork Reduction Act of 1995, effective October 1, 1995. The information collection packages that may be included in this notice are for new information collections, approval of existing information collections, revisions to OMB-approved information collections, and extensions (no change) of OMB-approved information collections.

SSA is soliciting comments on the accuracy of the agency's burden estimate; the need for the information; its practical utility; ways to enhance its quality, utility, and clarity; and on ways to minimize burden on respondents, including the use of automated collection techniques or other forms of information technology. Written comments and recommendations regarding the information collection(s) should be submitted to the OMB Desk Officer and the SSA Reports Clearance Officer. The information can be mailed, faxed or e-mailed to the individuals at the addresses and fax numbers listed below:

(OMB), Office of Management and Budget, Attn: Desk Officer for SSA, Fax: 202–395–6974, E-mail address: *OIRA_Submission@omb.eop.gov*.

(SSA), Social Security Administration, DCFAM, Attn: Reports Clearance Officer, 1333 Annex Building, 6401 Security Blvd., Baltimore, MD 21235, Fax: 410–965–6400, E-mail address: *OPLM.RCO@ssa.gov*.

I. The information collections listed below are pending at SSA and will be submitted to OMB within 60 days from the date of this notice. Therefore, your comments should be submitted to SSA within 60 days from the date of this publication. You can obtain copies of the collection instruments by calling the SSA Reports Clearance Officer at 410–965–0454 or by writing to the address listed above.

1. *Work History Report—20 CFR 404.1512 and 416.912—0960–0578.* The information collected by form SSA–3369 is needed to determine disability by the State Disability Determination Services (DDS). The information will be used to document an individual's past work history. The respondents are applicants for Supplemental Security

Income (SSI) disability payments and Social Security disability benefits.

Type of Request: Extension of an OMB-approved information collection.

Number of Respondents: 1,000,000.

Frequency of Response: 1.

Average Burden Per Response: 30 minutes.

Estimated Annual Burden: 500,000 hours.

2. *Beneficiary Interview and Auditor's Observations Form—0960–0630.* The information collected through the Beneficiary Interview and Auditor's Observation Form, SSA–322, will be used by SSA's Office of the Inspector General to interview beneficiaries and/or their payees to determine whether representative payees are complying with their duties and responsibilities under SSA's regulations at 20 CFR 404.2035 and 416.635. Respondents to this collection will be randomly selected SSI recipients and Social Security beneficiaries who have representative payees.

Type of Request: Extension of an OMB-approved information collection.

Number of Respondents: 2,550.

Frequency of Response: 1.

Average Burden Per Response: 15 minutes.

Estimated Annual Burden: 638 hours.

3. *Report to U.S. SSA by Person Receiving Benefits for a Child or Adult Unable to Handle Funds & Report to U.S. SSA*—0960–0049. SSA needs the information on Form SSA–7161–OCR–SM to monitor the performance of representative payees outside the U.S. and the information on Form SSA–7162–OCR–SM to determine continuing entitlement to Social Security benefits and correct benefit amounts for beneficiaries outside the U.S. The respondents are individuals outside the U.S. who are receiving benefits either for someone else, or on their own behalf, under title II of the Social Security Act.

Type of Request: Revision of an OMB-approved information collection.

Form number	Number of respondents	Frequency of response	Average burden per response (minutes)	Estimated annual burden (hours)
SSA–7161–OCR–SM	30,000	1	15	7,500
SSA–7162–OCR–SM	236,500	1	5	19,708
Totals	257,000			27,208

4. *Real Property Current Market Value Estimate—0960–0471.* The SSA–L2794 is used to obtain current market value estimates of real property owned by applicants for, or beneficiaries of, Supplemental Security Income payments (or a person whose resources are deemed to such an individual). The value of an individual's resources, including non-home real property is one of the eligibility requirements for SSI payments. The respondents are individuals with knowledge of local real property values.

Type of Request: Extension of an OMB-approved information collection.

Number of Respondents: 5,438.

Frequency of Response: 1.

Average Burden Per Response: 20 minutes.

Estimated Annual Burden: 1,813 hours.

5. *Requests for Self-Employment Information, Employee Information, Employer Information—20 CFR 422.120—0960–0508.* SSA uses forms SSA–L2765, SSA–L3365 and SSA–L4002 to request correct information when an employer, employee or self-employed person reports an individual's earnings without a Social Security Number (SSN) or with an incorrect name or SSN. The respondents are employers, employees or self-employed individuals who are requested to furnish additional identifying information.

Type of Request: Revision of an OMB-approved information collection.

Form number	Number of respondents	Frequency of response	Average burden per response (minutes)	Estimated annual burden (hours)
SSA–L2765	15,400	1	10	2,567
SSA–L3365	173,100	1	10	28,850
SSA–L4002	656,000	1	10	109,333
Total	844,500			140,750

6. *Cost Reimbursable Research Request—0960–NEW.*

Background

The Social Security Administration (SSA) is responsible for administrating two cash benefit programs, notably the Old-Age, Survivors, and Disability Insurance (OASDI) and SSI programs. To carry out this task, SSA maintains a number of files with detailed information on individuals and their characteristics, such as demographics, employment, earnings, assets, disability diagnosis, location, and other information. While designed for SSA to carry out its administrative tasks, the data files offer great informational depth to researchers interested in SSA's programs and other research areas. As a result, SSA provides qualified researchers needing agency administrative data for a variety of projects.

SSA's data files are governed by strict confidentiality restrictions and are not publicly accessible. Therefore, SSA has charged the Office of Research, Evaluation, and Statistics (ORES) as the primary interface for researchers, either within SSA or outside of it, who seek access to SSA's program files. To safeguard the information and the public trust, ORES has established comprehensive unified application process procedures for obtaining program data for research use.

The Cost Reimbursable Research Request

To request SSA program data for research, the researcher must submit a

completed research application for SSA's evaluation. In the application, the requesting researcher must provide required basic project information and describe the way in which the proposed project will further SSA's mission to promote the economic security of the nation's people through its administration of the OASDI programs, and/or the SSI program. Depending on the type of research data needed, the requesting researchers may be required to provide SSA with up to 14 [1] prescribed project information elements to properly assess their data request.

Once the application is reviewed and approved by ORES a Reimbursable Conditions of Use Agreement is signed with the requestor which outlines the conditions and safeguards agreed to for the research project data exchange. The requestor may use the data for research and statistical purposes only. This is a reimbursable service and SSA recovers all expenses incurred in providing this information. The respondents to this information collection are the qualified researchers that request SSA administrative data for a variety of projects. These applicants include but are not limited to Federal and State government agencies and/or their contractors, private entities, and colleges/universities.

Type of Request: Collection in use without OMB Control Number.

Number of Respondents: 15.

Frequency of Response: 1.

Average Burden per Response: 240 minutes.

Estimated Annual Burden: 60 hours.

The total average annual cost for all respondents to use this service is approximately $112,500 or an average of $7,500 to complete a single request. This cost projection is an estimate of SSA's administrative and systems costs to analyze and provide the requested research data. Since this is a reimbursable, service all associated cost are borne by the requesters.

7. *Notice Regarding Substitution of Party On Death of Claimant-Reconsideration of Disability Cessation—20 CFR 404.917–404.921 and 416.1407–416.1421—0960–0351.* Form SSA–770 is used when a claimant dies before a determination is made on that person's request for reconsideration on his/her disability cessation. SSA seeks a qualified substitute party to pursue the appeal. If the qualified substitute party is located, the SSA–770 is used to collect information regarding whether to pursue or withdraw the reconsideration request. The information collected on the SSA–770 forms the basis of the decision to continue or discontinue the appeals process. Respondents are substitute applicants who are pursuing a reconsideration request for a deceased claimant.

Type of Request: Extension of an OMB-approved information collection.

Number of Respondents: 1,200.

Frequency of Response: 1.

Average Burden Per Response: 5 minutes.

Estimated Annual Burden: 100 hours.

II. The information collections listed below have been submitted to OMB for clearance. Your comments on the information collections would be most useful if received by OMB and SSA within 30 days from the date of this publication. You can obtain a copy of the OMB clearance packages by calling the SSA Reports Clearance Officer at 410–965–0454, or by writing to the address listed above.

1. *Response to Notice of Revised Determination—20 CFR 404.913–.914 and 992(b), 416.1413–.1414 and 1492—0960–0347.* Form SSA–765 is used by claimants to request a disability hearing and/or to submit additional evidence before a revised reconsideration determination is issued. The respondents are claimants who file for a disability hearing in response to a notice of revised determination for disability under the OASDI and SSI programs.

Type of Request: Extension of an OMB-approved information collection.

Number of Respondents: 1,925.

Frequency of Response: 1.

Average Burden Per Response: 30 minutes.

Estimated Annual Burden: 963 hours.

2. *Questionnaire about Employment or Self-Employment Outside the United States—20 CFR 404.401(b)(1), 404.415, 404.417—0960–0050.* The information collected on the SSA–7163 is needed to determine whether work performed by beneficiaries outside the United States is cause for deductions from their monthly Social Security Title II benefits; to determine which of two work tests (foreign test or regular test) is applicable; and to determine the months, if any, for which deductions should be imposed. The respondents are Title II beneficiaries living and working outside the United States.

Type of Request: Extension of an OMB-approved information collection.

Number of Respondents: 20,000.

Frequency of Response: 1.

Average Burden Per Response: 12 minutes.

Estimated Annual Burden: 4,000 hours.

3. *Medical Permit Parking Application—41 CFR 101–20.104–2—0960–0624.* SSA issues medical parking assignments at SSA-owned and -leased facilities to individuals who have a medical condition which meets the criteria for medical parking. In order to issue a medical parking permit, SSA must obtain medical evidence from the applicant's physician. Form SSA–3192-F4 is used to collect this information. SSA then uses the information to determine whether the individual qualifies for a medical parking permit and whether or not to issue the permit. The respondents are physicians of applicants for medical parking permits.

Type of Request: Extension of an OMB-approved information collection.

Number of Respondents: 800.

Frequency of Response: 1.

Average Burden Per Response: 60 minutes.

Estimated Annual Burden: 800 hours.

4. *Reporting Changes that Affect Your Social Security Payment*—20 CFR 404.301–305, .310–311, .330–.333, .335–.341, .350–.352, .370–.371, 401–.402, .408(a), .421–.425, .428–.430, .434–.437, .439–.441, 446–.447, .450–.455, .468—0960–0073. SSA uses the information collected on Form SSA–1425 to determine continuing entitlement to Title II Social Security benefits and to determine the proper benefit amount. The respondents are Social Security beneficiaries receiving SSA retirement, disability or survivor's auxiliary benefits who need to report an event that could affect payments.

Type of Request: Revision of an OMB-approved information collection.

Number of Respondents: 70,000.

Frequency of Response: 1.

Average Burden Per Response: 5 minutes.

Estimated Annual Burden: 5,833 hours.

5. *Disability Hearing Officer's Decision—20 CFR 404.917 and 416.1417—0960–0441.* The Social Security Act requires that SSA provide an evidentiary hearing at the reconsideration level of appeal for claimants who have received an initial or revised determination that a disability did not exist or has ceased. Based on the hearing, the disability hearing officer (DHO) completes form SSA–1207 and all applicable supplementary forms (which vary depending on the type of claim). The DHO uses the information in documenting and preparing the disability decision. The form will aid the DHO in addressing the crucial elements of the case in a sequential and logical fashion. The respondents are DHOs in the State DDSs.

[1] The complete application process is described in SSA's Program Data User Manual.

Type of Request: Extension of an OMB-approved information collection.

Number of Respondents: 65,000.

Frequency of Response: 1.

Average Burden Per Response: 45 minutes.

Estimated Annual Burden: 48,750 hours.

6. *Statement for Determining Continuing Eligibility, Supplemental Security Income Payment(s)—20 CFR Subpart B, 416.204—0960–0416.* SSA uses the information collected on form SSA–8203–BK for high-error-profile (HEP) redeterminations of disability to determine whether SSI recipients have met and continue to meet all statutory and regulatory requirements for SSI eligibility and whether they have been, and are still receiving, the correct payment amount. The information is normally completed in field offices by personal contact (face-to-face or telephone interview) using the automated Modernized SSI Claim System (MSSICS). The respondents are recipients of Title XVI benefits.

Type of Request: Revision of an OMB-approved information collection.

Collection method	Number of respondents	Frequency of response	Average burden per response (minutes)	Estimated annual burden (hours)
MISSICS	109,012	1	20	36,337
MISSICS/Signature Proxy	36,338	1	19	11,507
Paper	25,650	1	20	8,550
Totals:	171,000			56,394

7. *Information Collections Conducted by State DDSs on Behalf of SSA*—20 CFR 404.1503a, 404.1512, 404.1513404.1512, 404.1513, 404.1514 404.1517, 404.1519; 20 CFR subpart Q, 404.1613, 404.1614, 404.1624; 20 CFR subpart I, 416.903a, 416.912, 416.913, 416.914, 416.917, 416.919 and 20 CFR subpart J, 416.1013, 416.1024, 416.1014—0960–0555. The State DDSs collect certain information that SSA needs to correctly administer its disability program. This information is divided into the Consultative Examination (CE) and Medical Evidence of Record (MER) categories. There are three types of CE evidence: (a) Medical evidence from CE providers, in which DDSs use CE medical evidence to make disability determinations when the claimant's own medical sources cannot or will not provide the required information, (b) CE claimant completion of a response form where claimants indicate if they intend to keep their CE appointment, and (c) CE claimant completion of a form indicating whether they want the CE report to be sent to their doctor. In the MER category, the DDSs use MER information to determine a person's physical and/or mental status prior to making a disability determination. Please note that for the first time, some of the information included in this collection can be submitted electronically through the new Electronic Records Express (ERE) systems. The respondents are medical providers, other sources of MER, and disability claimants.

Type of Collection: Revision to an existing OMB-approved collection.

CE

a. Medical Evidence From CE Providers

	Number of respondents	Frequency of response	Average burden per response (minutes)	Estimated Annual Burden (hours)
Paper Submissions	1,215,000	1	30	607,500
ERE Submisions	285,000	1	15	71,250
Totals	1,500,000			678,750

b. Claimants re Appointment Letter

Number of Respondents: 750,000.

Frequency of Response: 1.

Average Burden Per Response: 5 minutes.

Estimated Annual Burden: 62,500 hours.

c. Claimants re Report to Medical Provider

Number of Respondents: 1,500,000.

Frequency of Response: 1.

Average Burden Per Response: 5 minutes.

Estimated Annual Burden: 125,000 hours.

MER:

	Number of respondents	Frequency of response	Average burden per response (minutes)	Estimated annual burden (hours)
Paper submissions	2,480,800	1	15	620,200
C/D (Connect Direct, commercially available software used for electronically transferring medical records)	218,400	1	15	54,600
ERE	100,800		7	11,760
Totals	2,800,000			686,560

Dated: March 8, 2007.

Elizabeth A. Davidson,

Reports Clearance Officer, Social Security Administration.

[FR Doc. E7–4654 Filed 3–14–07; 8:45 am]

BILLING CODE 4191–02–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

Public Notice for Waiver of Aeronautical Land-Use Assurance; Rickenbacker International Airport, Columbus, OH

AGENCY: Federal Aviation Administration, DOT.

ACTION: Notice of intent of waiver with respect to land.

SUMMARY: The Federal Aviation Administration (FAA) is considering a proposal to change a portion of the airport from aeronautical use to non-aeronautical use and to authorize the release of 250.357 acres of vacant airport property currently being used for agricultural purposes for the proposed development of bulk warehouse/distribution facilities as a component of the Rickenbacker Global Logistics Park. The land was acquired by the Rickenbacker Port Authority through Quitclaim Deed dated March 30, 1984 from the Administrator of General Services for the United States of America. There are no impacts to the airport by allowing the airport to dispose of the property. Approval does not constitute a commitment by the FAA to financially assist in the disposal of the subject airport property nor a determination of eligibility for grant-in-aid funding from the FAA. The CRAA will receive $5,383,000 for the parcel. In accordance with section 47107(h) of title 49, United States Code, this notice is required to be published in the **Federal Register** 30 days before modifying the land-use assurance that requires the property to be used for an aeronautical purpose.

DATES: Comments must be received on or before April 16, 2007.

ADDRESSES: Written comments on the Sponsor's request must be delivered or mailed to: Mary W. Jagiello, Program Manager, Detroit Airports District Office, 11677 South Wayne Road, Suite 107, Romulus, MI 48174.

FOR FURTHER INFORMATION CONTACT: Mary W. Jagiello, Program Manager, Federal Aviation Administration, Great Lakes Region, Detroit Airports District Office, DET ADO–608, 11677 South Wayne Road, Suite 107, Romulus, Michigan 48174. Telephone Number (734–229–2956)/FAX Number (734–229–2950). Documents reflecting this FAA action may be reviewed at this same location or at Rickenbacker International Airport, Columbus, Ohio.

SUPPLEMENTARY INFORMATION: Following is a legal description of the property situated in the State of Ohio, County of Pickaway, Township of Madison, Section 18, Township 10, Range 21 and Township of Harrison, Section 13, Township 3, Range 22 of the Congress Lands, and being part of (Tract 1) as conveyed to Columbus Municipal Airport Authority by deed of record in Official Record 514, Page 2561, records of the Recorder's Office, Pickaway County, Ohio, being more particularly described as follows: Beginning at the centerline intersection of Airbase road (County Road 237) and Ashville Pike (County Road 28), being an angle point in the said (Tract 1) boundary;

Thence North 03°43′38″ East, a distance of 2551.67 feet, along the centerline of said Ashville Pike to a point;

Thence the following three (3) courses and distances on, over and across the said (Tract 1):

1. South 86°24′00″ East, a distance of 2692.98 feet, to a point;
2. North 03°47′28″ East, a distance of 93.39 feet, to a point;
3. South 86°24′00″ East, a distance of 1564.12 feet, to an angle point in said (Tract 1) boundary, being the northwest corner of a 201.7757 acre tract conveyed to The Landings at Rickenbacker, LLC by deed of record in Official Record 263, Page 721;

Thence South 03°36′05″ West, a distance of 2603.18 feet, along the westerly line of said 201.7757 acre tract a line common to said (Tract 1) to the southwest corner of said 201.7757 acre tract, said corner being in the centerline of said Airbase Road;

Thence North 86°35′17″ West, a distance of 1572.77 feet, along the centerline of said Airbase Road and the southerly line of said (Tract 1) to a point at the intersection with Lockbourne Eastern Road (Township Road 31), being in the line between Madison and Harrison Townships;

Thence North 87°10′55″ West, a distance of 2690.50 feet, continuing the centerline of said Airbase Road and the southerly line of said (Tract 1) to the Point of Beginning, containing 250.357 acres, more or less.

The bearings shown herein are based on the bearing of North 87°10′55″ West for the centerline of Airbase Road being the most southerly boundary line of the 2995.065 acre (981.384 acre Pickaway County) (Tract 1).

Issued in Romulus, Michigan, on February 28, 2007.

Irene R. Porter,

Manager, Detroit Airports District Office, FAA, Great Lakes Region.

[FR Doc. 07–1204 Filed 3–14–07; 8:45 am]

BILLING CODE 4910–13–M

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

Agency Information Collection Activity Seeking OMB Approval

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice.

SUMMARY: The FAA invites public comments about our intention to request the Office of Management and Budget's (OMB) revision of a current information collection. The Federal Register Notice with a 60-day comment period soliciting comments on the following collection of information was published on December 5, 2006, vol. 71, no. 233, page 70579. 14 CFR part 141 prescribes requirements for pilot schools certification. Information collected is used for certification and to determine compliance.

DATES: Please submit comments by April 16, 2007.

FOR FURTHER INFORMATION CONTACT: Carla Mauney at *Carla.Mauney@faa.gov.*

SUPPLEMENTARY INFORMATION:

Federal Aviation Administration (FAA)

Title: Pilot Schools—FAR 141.

Type of Request: Extension of a currently approved collection.

OMB Control Number: 2120–0009.

Form(s): FAA Form 8420–8.

Affected Public: An estimated 546 Respondents.

Frequency: This information is collected on occasion.

Estimated Average Burden Per Response: Approximately 54.5 hours per response.

Estimated Annual Burden Hours: An estimated 29,770 hours annually.

Abstract: Chapter 447, Subsection 44707, authorizes certification of civilian schools giving instruction in flying. 14 CFR part 141 prescribes requirements for pilot schools certification. Information collected is used for certification and to determine compliance. The respondents are applicants who wish to be issued pilot school certificates and associated ratings.

ADDRESSES: Interested persons are invited to submit written comments on the proposed information collection to

the Office of Information and Regulatory Affairs, Office of Management and Budget. Comments should be addressed to Nathan Lesser, Desk Officer, Department of Transportation/FAA, and sent via electronic mail to *oira_submission@omb.eop.gov* or faxed to (202) 395–6974. Comments are invited on: Whether the proposed collection of information is necessary for the proper performance of the functions of the Department, including whether the information will have practical utility; the accuracy of the Department's estimates of the burden of the proposed information collection; ways to enhance the quality, utility, and clarity of the information to be collected; and ways to minimize the burden of the collection of information on respondents, including the use of automated collection techniques or other forms of information technology.

Issued in Washington, DC, on March 9, 2007.

Carla Mauney,

FAA Information Collection Clearance Officer, Strategy and Investment Analysis Division, AIO–20.

[FR Doc. 07–1205 Filed 3–14–07; 8:45 am]

BILLING CODE 4910–13–M

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

Agency Information Collection Activity Seeking OMB Approval

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice.

SUMMARY: The FAA invites public comments about our intention to request the Office of Management and Budget's (OMB) revision of a current information collection. The **Federal Register** Notice with a 60-day comment period soliciting comments on the following collection of information was published on September 14, 2006, vol. 71, no. 178, page 54330. The FAA Office of Commercial Space Transportation (AST) conducts this survey in order to obtain industry input on customer service standards which have been developed and distributed to industry customers.

DATES: Please submit comments by April 16, 2007.

FOR FURTHER INFORMATION CONTACT: Carla Mauney at *Carla.Mauney@faalgov.*

SUPPLEMENTARY INFORMATION:

Federal Aviation Administration (FAA)

Title: Associate Administrator for Commercial Space Transportation (AST) Customer Service Survey.

Type of Request: Revision of a currently approved collection.

OMB Control Number: 2120–0611.

Forms(s): There are no FAA forms associated with this collection,.

Affected Public: An estimated 50 Respondents.

Frequency: This information is collected semi-annually.

Estimated Average Burden per Response: Approximately 1 hour per response.

Estimated Annual Burden Hours: An estimated 50 hours annually.

Abstract: The FAA Office of Commercial Space Transportation (AST) conducts this survey in order to obtain industry input on customer service standards which have been developed and distributed to industry customers. This activity is responsive to the Organizational Excellence/Customer Service goals outlined in the Federal Aviation Administration Flight Plan, the 10-year strategic plan. AST collects and analyzes the data for results.

ADDRESSES: Interested persons are invited to submit written comments on the proposed information collection to the Office of Information and Regulatory Affairs, Office of Management and Budget. Comments should be addressed to Nathan Lesser, Desk Officer, Department of Transportation/FAA, and sent via electronic mail to *oira_submission@omb.eop.gov* or faxed to (202) 395–6974.

Comments are invited on: Whether the proposed collection of information is necessary for the proper performance of the functions of the Department, including whether the information will have practical utility; the accuracy of the Department's estimates of the burden of the proposed information collection; ways to enhance the quality, utility, and clarity of the information to be collected; and ways to minimize the burden of the collection of information on respondents, including the use of automated collection techniques or other forms of information technology.

Issued in Washington, DC, on March 9, 2007.

Carla Mauney,

FAA Information Collection Clearance Officer, Strategy and Investment Analysis Division, AIO–20.

[FR Doc. 07–1206 Filed 3–14–07; 8:45 am]

BILLING CODE 4910–13–M

DEPARTMENT OF TRANSPORTATION

Federal Highway Administration

Environmental Impact Statement; Knox County, City of Vincennes, Indiana and Lawrence County, IL

AGENCY: Federal Highway Administration (FHWA), DOT.

ACTION: Notice of intent.

SUMMARY: The Federal Highway Administration (FHWA) is issuing this notice to advise the public that FHWA will prepare an Environmental Impact Statement (EIS) for the relocation of railroad lines in Knox County, Indiana and Lawrence County, Illinois. The proposed rail relocation study will involve the relocation of the two CSX Transportation (CSXT) railroad mainline tracks, the north-south mainline and the east-west mainline that traverses through the City of Vincennes and portions of Knox County, Indiana and Lawrence County Illinois.

DATES: Comments on the scope of the EIS for the proposed project should be forwarded no later than April 16, 2007.

ADDRESSES: Address all comments concerning this notice to Brock Hoegh, Project Planner, HNTB Indiana, Inc., 111 Monument Circle, Suite 1200, Indianapolis, IN 46204, Telephone: (317) 636–4682, E-mail: *bhoegh@hntb.com.*

FOR FURTHER INFORMATION CONTACT: Larry Heil, Environmental Specialist, Federal Highway Administration, Telephone: (317) 226–7480; or Frank Litherland, INDOT Project Manager, Telephone 812–882–8364.

SUPPLEMENTARY INFORMATION: The FHWA, in cooperation with the Indiana Department of Transportation (INDOT) and the Illinois Department of Transportation (IDOT), will prepare an EIS to evaluate alternative alignments for the relocation of the two CSXT railroad mainline tracks, the north-south mainline and the east-west mainline that traverses through the City of Vincennes and portions of Knox County, Indiana and Lawrence County, Illinois. The north-south mainline is CSXT's main route from Chicago to points south and southeast. The east-west mainline is one of CSXT's routes to St. Louis. The east-west mainline extends from Cincinnati to St. Louis. The two mainlines cross just north of downtown. The majority of the train traffic travels on the north-south CSXT mainline and consists of approximately 50 trains per day. The east-west mainline has approximately 15 trains

per day. The relocation of the north-south mainline will require the construction of a new corridor approximately 10 to 13 miles in length depending on the alignment alternative. The east-west corridor may be approximately 8 to 9 miles in length. The relocation of the railroad corridors would eliminate at least 47 grade crossings. The relocated rail corridors would be entirely grade separated.

The numerous grade crossings with high vehicle traffic volumes within the city limits require the CSXT trains to reduce speed as they pass through Vincennes. Two CSXT mainlines cross in the middle of the city, and trains that switch between mainlines move slowly, creating traffic backups, emergency vehicle delays, and delays in rail operations. Frequently, train movements literally cut the city in half. In addition, the large volumes of trains and vehicular traffic crossing the railroad corridor increase the probability of collisions at the crossings.

Cooperating Agencies: The Federal Railroad Administration has agreed to serve as a cooperating agency. No others have been yet identified for this project.

Environmental Issues: Possible environmental impacts include displacement of commercial and residential properties, increased noise in some areas, decreased noise in other areas, effects to historical properties or archaeological sites, viewshed impacts, impacts to water resources, wetlands, farmed wetlands, prime farmland, sensitive biological species and habitat, land use compatibility impacts, and impacts to agricultural lands.

Alternatives: The EIS will consider alternatives that include: (1) Taking no action; (2) rail relocation and reconstruction of railroad line(s) and grade separations on new location.

Scoping and Comment: FHWA encourages broad participation in the EIS process and review of the resulting environmental documents. A scoping meeting will be conducted in the City of Vincennes area at a date and place, which will be widely publicized well in advance of the meeting. Comments, questions, and suggestions related to the project and potential environmental concerns are invited from all interested agencies and the public at large to ensure that the full range of issues related to the proposed action and all reasonable alternatives are considered and all significant issues are identified. These comments, questions, and suggestions should be forwarded to the address listed above. The public is invited to participate in the scoping process as well. Notices of availability for the Draft EIS, Final EIS, and Record of Decision will be provided through direct mail, the **Federal Register** and other media. Notification also will be sent to Federal, State, local agencies, persons, and organizations that submit comments or questions. Precise schedules and locations for public meetings will be announced in the local news media. Interested individuals and organizations may request to be included on the mailing list for the distribution of meeting announcements and associated information.

(Catalog of Federal Domestic Assistance Program No. 20.205, Highway Planning and Construction. The regulations implementing Executive Order 12372 regarding intergovernmental consultation on Federal programs and activities apply to the program).

Authority: 23 U.S.C. 315; 23 CFR 771.123; 49 CFR 1.48.

Issued on: March 9, 2007.

Robert F. Tally, P.E.,

Division Administrator, Indianapolis, Indiana.

[FR Doc. E7–4725 Filed 3–14–07; 8:45 am]

BILLING CODE 4910–22–P

DEPARTMENT OF TRANSPORTATION

Federal Railroad Administration

Environmental Impact Statement for the California High Speed Train System From Los Angeles to Orange County, CA

AGENCY: Federal Railroad Administration (FRA) Department of Transportation (DOT).

ACTION: Notice of Intent to Prepare an Environmental Impact Statement.

SUMMARY: FRA is issuing this notice to advise the public that FRA and the California High Speed Rail Authority (Authority) will jointly prepare a project level Environmental Impact Statement (EIS) and project level Environmental Impact Report (EIR) for the section of the Authority's proposed California High-Speed Train (HST) System from the City of Los Angeles (Union Station) to Orange County (Anaheim) in compliance with relevant State and federal laws, in particular the California Environmental Quality Act (CEQA) and the National Environmental Policy Act (NEPA).

FRA is issuing this notice to solicit public and agency input into the development of the scope of the EIS and to advise the public that outreach activities conducted by the Authority and its representatives will be considered in the preparation of the combined EIR/EIS. The Authority and FRA completed a Program EIR/EIS for the California HST System in 2005 as the first-phase of a tiered environmental review process for the proposed California HST System. The Authority certified the Final Program EIR and issued a decision, and FRA issued a Record of Decision in November 2005 on the Final Program EIS, selecting the HST Alternative for further project level environmental review and selecting corridor alignments and potential station locations, including a corridor between Los Angeles and Orange County. The preparation of this project level Los Angeles-Orange County HST EIR/EIS will involve development of preliminary engineering designs and assessment of environmental effects associated with the construction, operation, and maintenance of the HST system, including track, ancillary facilities and stations, along the previously selected Los Angeles-Orange County corridor.

DATES: Written comments on the scope of the Los Angeles-Orange County HST EIR/EIS should be provided to the Authority by April 24, 2007. Public scoping meetings are scheduled from April 5–April 12, 2007, as noted below.

ADDRESSES: Written comments on the scope should be sent to Mr. Dan Leavitt, Deputy Director, ATTN. Los Angeles—Orange County, California High-Speed Rail Authority, 925 L Street, Suite 1425, Sacramento, CA 95814, or via e-mail with the subject line ''Los Angeles-Orange County HST'' to: *comments@hsr.ca.gov*. Comments may also be provided orally or in writing at the scoping meetings scheduled at the following locations:

- *Union Station/METRO* (Los Angeles), METRO Board Room, One Gateway Plaza, Los Angeles, CA 90012, on April 5, 2007, from 3 p.m. to 5 p.m. and from 6 p.m. to 8 p.m.
- *Anaheim*, Gordon Hoyt Conference Room, City Hall West, 201 S. Anaheim Boulevard, Anaheim, CA on April 11, 2007, from 3 p.m. to 5 p.m. and from 6 p.m. to 8 p.m..
- *Norwalk*, Arts & Sports Complex Community Meeting Center (Sproul Room), 13000 Clarkdale Avenue, Norwalk, CA 90651 on April 12, 2007, from 3 p.m. to 5 p.m. and from 6 p.m. to 8 p.m..

FOR FURTHER INFORMATION CONTACT: Mr. David Valenstein, Environmental Program Manager, Office of Railroad Development, Federal Railroad Administration, 1120 Vermont Avenue (Mail Stop 20), Washington, DC 20590; Telephone (202) 493–6368, or Mr. Leavitt at the above noted address.

SUPPLEMENTARY INFORMATION: The California High-Speed Rail Authority (Authority) was established in 1996 and is authorized and directed by statute to undertake the planning for the development of a proposed statewide HST network that is fully coordinated with other public transportation services. The Legislature has granted the Authority the powers necessary to oversee the construction and operation of a statewide HST network once financing is secured. As part of the Authority's efforts to implement a high-speed train system, the Authority adopted a Final Business Plan in June 2000, which reviewed the economic feasibility of a 700-mile long HST system capable of speeds in excess of 200 miles per hour on a dedicated, fully grade-separated state-of-the art track.

The FRA has responsibility for oversight of the safety of railroad operations, including the safety of any proposed high-speed ground transportation system. For the proposed HST, it is anticipated that FRA would need to take certain regulatory actions prior to operation.

In 2005, the Authority and FRA completed a Final Program EIR/EIS for the Proposed California High-Speed Train System (statewide program EIR/EIS), as the first-phase of a tiered environmental review process. The Authority certified the Final Program EIR under CEQA and approved the proposed HST System, and FRA issued a Record of Decision under NEPA on the Final Program EIS. This statewide program EIR/EIS established the purpose and need for the HST system, analyzed a HST alternative, and compared it with a No Project/No Action Alternative and a Modal Alternative. In approving the statewide program EIR/EIS, the Authority and FRA selected the HST Alternative and selected certain corridors/general alignments and general station locations, incorporated mitigation strategies and design practices, and specified further measures to guide the development of the HST System at the site-specific project level of environmental review to avoid and minimize potential adverse environmental impacts.

The Los Angeles-Orange County HST EIR/EIS will be developed as a second-tier, site-specific environmental document. It is one of a number of second-tier environmental reviews for sections of the HST system that FRA and the Authority intend to undertake. It will be tiered from and incorporate by reference the certified statewide program EIR/EIS in accordance with Council on Environmental Quality (CEQ) regulations (40 CFR 1508.28) and State CEQA Guidelines (14 C.C.R. § 15168[b]). Tiering will ensure that the Los Angeles-Orange County HST EIR/EIS builds upon all previous work prepared for and incorporated in the statewide program EIR/EIS. The EIR/EIS will be carried out in accordance with FRA's Procedures for Considering Environmental Impacts (64 FR 28545 [May 26, 1999]) and will address not only NEPA and CEQA, but other applicable statutes, regulations and executive orders, including the 1990 Clean Air Act Amendments, Section 404 of the Clean Water Act, the National Historic Preservation Act of 1966, Section 4(f) of the Department of Transportation Act, the Endangered Species Act, and Executive Order 12898 on Environmental Justice. This EIR/EIS process will also continue the NEPA/Clean Water Act Section 404 merger process established through the statewide program EIR/EIS process.

The Los Angeles-Orange County HST EIR/EIS and other project level EIR/EISs will examine a range of project alternatives for portions of the proposed HST system within corridors selected in the statewide program EIR/EIS, as well as a no action alternative. This and other project level EIR/EISs will fully describe site-specific environmental impacts and will identify specific mitigation measures to address those impacts and will incorporate design practices to avoid and minimize potential adverse environmental impacts. The FRA and the Authority will assess the site characteristics, size, nature, and timing of proposed site-specific projects to determine whether the impacts are potentially significant and whether impacts can be avoided or mitigated. This and other project EIR/EISs will identify and evaluate reasonable and feasible site-specific alignment alternatives, evaluate the impacts from construction, operation, and maintenance of the HST system, and identify mitigation measures. Information and documents regarding the HST environmental review process will be made available through the Authority's Internet site: *http://www.cahighspeedrail.gov/*.

Purpose and Need: The need for a HST system is directly related to the expected growth in population, and increases in intercity travel demand in California over the next twenty years and beyond. With growth in travel demand, there will be an increase in travel delays arising from the growing congestion on California's highways and at airports. In addition, there will be negative effects on the economy, quality of life, and air quality in and around California's metropolitan areas from a transportation system that will become less reliable as travel demand increases. The intercity highway system, commercial airports, and conventional passenger rail serving the intercity travel market are currently operating at or near capacity, and will require large public investments for maintenance and expansion to meet existing demand and future growth. The purpose of the proposed HST system is to provide a new mode of high-speed intercity travel that would link the major metropolitan areas of the state; interface with international airports, mass transit, and highways; and provide added capacity to meet increases in intercity travel demand in California in a manner sensitive to and protective of California's unique natural resources.

Alternatives: The Los Angeles-Orange County HST EIR/EIS will consider a No Action or No Project Alternative and HST Alternatives for the Los Angeles to Orange County corridor.

No Action Alternative: The take no action (No Project or No Build) alternative is defined to serve as the baseline for assessment of the HST Alternative. The No Build Alternative represents the region's transportation system (highway, air, and conventional rail) as it existed in 2006, and as it would exist after completion of programs or projects currently planned for funding and implementation by 2030. The No Build Alternative defines the existing and future intercity transportation system for the Los Angeles to Orange County corridor based on programmed and funded improvements to the intercity transportation system through 2030, according to the following sources of information: State Transportation Improvement Program (STIP), Regional Transportation Plans (RTPs) for all modes of travel, airport plans, and intercity passenger rail plans.

HST Alternative: The Authority proposes to construct, operate and maintain an electric-powered steel-wheel-on-steel-rail HST system, over 700-mile long (1,126-kilometer long), capable of speeds in excess of 200 miles per hour (mph) (320 kilometers per hour [km/h]) on dedicated, fully grade-separated tracks, with state-of-the-art safety, signaling, and automated train control systems. The Los Angeles to Orange County corridor that was selected by the Authority and FRA with the statewide program EIR/EIS follows the existing BNSF/Metrolink rail corridor (also known as the LOSSAN Corridor) from Los Angeles Union Station as far south as Irvine. The Los Angeles-Orange County HST EIR/EIS

will consider HST service from Los Angeles to Anaheim. The HST system can provide service to Orange County with a terminus in Anaheim. Beyond Anaheim right-of-way is constrained and environmental conditions are different. HST service beyond Anaheim to Irvine may be considered separately in the future.

Further engineering studies to be undertaken as a part of this EIR/EIS process will examine and refine alignments in the selected corridor, including the alignment option identified in the statewide program EIR/EIS that shares tracks with other passenger services separated from freight trains with 4 total tracks (2 for passenger rail service and 2 for freight service) between Los Angeles and Fullerton and 2 total tracks with additional passing tracks South of Fullerton. With this alignment option, the electrified HST would share tracks (at reduced speeds) with non-electric Metrolink commuter rail, Amtrak Surfliner intercity services and occasional freight trains (there are fewer freight operations south of Fullerton). This alignment option is based on the premise that the capacity and compatibility issues associated with the shared operations with existing non-electric service (Surfliners, Metrolink, and freight) can be resolved. Additional alignment options will be considered that involve dedicated HST tracks that may be exclusive to HST service or that may also accommodate Metrolink express services.

Station location options were selected by the Authority and FRA with the statewide program EIR/EIS considering travel time, train speed, cost, local access times, potential connections with other modes of transportation, ridership potential, and the distribution of population and major destinations along the route, and local planning constraints/conditions. Alternative station sites at the selected general station locations will be identified and evaluated in this project level EIR/EIS. Station area development policies to encourage transit-friendly development near and around HST stations that would have the potential to promote higher density, mixed-use, pedestrian-oriented development will be prepared in coordination with local and regional planning agencies. Potential station locations to be evaluated in the Los Angeles-Orange County HST EIR/EIS include: City of Los Angeles-Union Station; City of Norwalk-Norwalk Transportation Center; and City of Anaheim-Anaheim Regional Transportation Intermodal Center (ARTIC). In addition, potential sites for turnback/layover train storage facilities and a main HST repair and heavy maintenance facility will be evaluated in the Los Angeles-Orange County HST EIR/EIS.

Probable Effects: The purpose of the EIR/EIS process is to explore in a public setting the effects of the proposed project on the physical, human, and natural environment. The FRA and the Authority will continue the tiered evaluation of all significant environmental, social, and economic impacts of the construction and operation of the HST system. Impact areas to be addressed include: Transportation impacts; safety and security; land use and zoning; secondary development; land acquisition, displacements, and relocations; cultural resource impacts, including impacts on historical and archaeological resources and parklands/recreation areas; neighborhood compatibility and environmental justice; natural resource impacts including air quality, wetlands, water resources, noise, vibration, energy, wildlife and ecosystems, including endangered species. Measures to avoid, minimize, and mitigate all adverse impacts will be identified and evaluated.

Scoping and Comments: FRA encourages broad participation in the EIS process during scoping and review of the resulting environmental documents. Comments and suggestions are invited from all interested agencies and the public at large to insure the full range of issues related to the proposed action and all reasonable alternatives are addressed and all significant issues are identified. In particular, FRA is interested in determining whether there are areas of environmental concern where there might be a potential for significant impacts identifiable at a project level. Public agencies with jurisdiction are requested to advise FRA and the Authority of the applicable permit and environmental review requirements of each agency, and the scope and content of the environmental information that is germane to the agency's statutory responsibilities in connection with the proposed project. Public agencies are requested to advise FRA if they anticipate taking a major action in connection with the proposed project and if they wish to cooperate in the preparation of the project level EIR/EIS. Public scoping meetings have been scheduled as an important component of the scoping process for both the State and Federal environmental review. The scoping meetings described in this Notice will also be advertised locally and included in additional public notification.

Issued in Washington, DC, on March 9, 2007.

Mark E. Yachmetz,

Associate Administrator for Railroad Development.

[FR Doc. E7–4710 Filed 3–14–07; 8:45 am]

BILLING CODE 4910–06–P

DEPARTMENT OF TRANSPORTATION

Federal Railroad Administration

Environmental Impact Statement for the California High Speed Train System from Palmdale to Los Angeles, CA

AGENCY: Federal Railroad Administration (FRA) U.S. Department of Transportation (DOT) .

ACTION: Notice of intent to prepare an Environmental Impact Statement.

SUMMARY: FRA is issuing this notice to advise the public that FRA and the California High Speed Rail Authority (Authority) will jointly prepare a project level Environmental Impact Statement (EIS) and project level Environmental Impact Report (EIR) for the section of the Authority's proposed California High-Speed Train (HST) System from the City of Palmdale to the City of Los Angeles in compliance with relevant State and federal laws, in particular the California Environmental Quality Act (CEQA) and the National Environmental Policy Act (NEPA).

FRA is issuing this notice to solicit public and agency input into the development of the scope of the EIS and to advise the public that outreach activities conducted by the Authority and its representatives will be considered in the preparation of the combined EIR/EIS. The Authority and FRA completed a Program EIR/EIS for the California HST System in 2005 as the first-phase of a tiered environmental review process for the proposed California HST System. The Authority certified the Final Program EIR and issued a decision, and FRA issued a Record of Decision in November 2005 on the Final Program EIS, selecting the HST Alternative for further project level environmental review and selecting corridor alignments and potential station locations, including a corridor between Palmdale and Los Angeles. The preparation of this project level Palmdale-Los Angeles HST EIR/EIS will involve development of preliminary engineering designs and assessment of environmental effects associated with the construction, operation and

maintenance of the HST system, including track, ancillary facilities and stations, along the previously selected Palmdale-Los Angeles corridor.

DATES: Written comments on the scope of the Palmdale-Los Angeles HST EIR/EIS should be provided to the Authority by April 24, 2007. Public scoping meetings are scheduled from April 4–17, 2007 as noted below.

ADDRESSES: Written comments on the scope should be sent to Mr. Dan Leavitt, Deputy Director, ATTN. Palmdale-Los Angeles, California High-Speed Rail Authority, 925 L Street, Suite 1425, Sacramento CA 95814, or via e-mail with subject line ''Palmdale-Los Angeles'' to: *comments@hsr.ca.gov*. Comments may also be provided orally or in writing at scoping meetings scheduled at the following locations:

- *Glendale Public Library*, 222 E. Harvard St., Glendale, CA 91205, on April 4, 2007 from 3 to 5 p.m. and from 6 to 8 p.m.
- *Los Angeles County Metropolitan Transit Agency Headquarters (Board Room)*, One Gateway Plaza, Los Angeles, CA 90012, on April 5, 2007 from 3 to 5 p.m. and from 6 to 8 p.m.
- *Sylmar Park Recreation Center*, 13109 Borden Avenue Sylmar, CA 91342 on April 10, 2007, from 3 to 5:00 p.m. and from 6 p.m. to 8 p.m.
- *Palmdale City Hall*, Council Chambers, 38300 North Sierra Highway, Palmdale, CA 93550, on April 12, 2007 from 3 to 5 p.m. and from 6 to 8 p.m.
- *Los Angeles River Center* & Gardens (Atrium), 570 W. Avenue 26, Los Angeles, CA 90065, on April 17, 2007 from 3 to 5 p.m. and from 6 to 8 p.m.

FOR FURTHER INFORMATION CONTACT: Mr. David Valenstein, Environmental Program Manager, Office of Railroad Development, Federal Railroad Administration, 1120 Vermont Avenue (Mail Stop 20), Washington, DC 20590; Telephone (202)–493–6368, or Mr. Leavitt at the above noted address.

SUPPLEMENTARY INFORMATION: The California High-Speed Rail Authority (Authority) was established in 1996 and is authorized and directed by statute to undertake the planning for the development of a proposed statewide HST network that is fully coordinated with other public transportation services. The Legislature has granted the Authority the powers necessary to oversee the construction and operation of a statewide HST network once financing is secured. As part of the Authority's efforts to implement a high-speed train system, the Authority adopted a Final Business Plan in June 2000, which reviewed the economic feasibility of a 700-mile-long HST system capable of speeds in excess of 200 miles per hour on a dedicated, fully grade-separated state-of-the-art track.

The FRA has responsibility for oversight of the safety of railroad operations, including the safety of any proposed high-speed ground transportation system. For the proposed HST, it is anticipated that FRA would need to take certain regulatory actions prior to operation.

In 2005, the Authority and FRA completed a Final Program EIR/EIS for the Proposed California High-Speed Train System (statewide program EIR/EIS), as the first-phase of a tiered environmental review process. The Authority certified the Final Program EIR under CEQA and approved the proposed HST System, and FRA issued a Record of Decision under NEPA on the Final Program EIS. This statewide program EIR/EIS established the purpose and need for the HST system, analyzed a HST alternative, and compared it with a No Project/No Action Alternative and a Modal Alternative. In approving the statewide program EIR/EIS, the Authority and the FRA selected the HST Alternative and selected certain corridors/general alignments and general station locations, incorporated mitigation strategies and design practices, and specified further measures to guide the development of the HST system at the site-specific project level of environmental review to avoid and minimize potential adverse environmental impacts.

The Palmdale-Los Angeles HST EIR/EIS will be developed as a second-tier, site-specific environmental document. It is one of a number of second-tier environmental reviews for sections of the HST system that FRA and the Authority intend to undertake. It will be tiered from and incorporate by reference the certified statewide program EIR/EIS in accordance with Council on Environmental Quality (CEQ) regulations (40 CFR 1508.28) and State CEQA Guidelines (14 C.C.R. 15168[b]). Tiering will ensure that the Palmdale-Los Angeles HST EIR/EIS builds upon all previous work prepared for and incorporated in the statewide program EIR/EIS. The EIR/EIS will be carried out in accordance with FRA's Procedures for Considering Environmental Impacts (64 FR 28545 [May 26, 1999]) and will address not only NEPA and CEQA but other applicable statutes, regulations and executive orders, including the 1990 Clean Air Act Amendments, Section 404 of the Clean Water Act, the National Historic Preservation Act of 1966, Section 4(f) of the Department of Transportation Act, the Endangered Species Act, and Executive Order 12898 on Environmental Justice. This EIR/EIS process will also continue the NEPA/Clean Water Act Section 404 merger process established through the statewide program EIR/EIS process.

This Palmdale-Los Angeles HST EIR/EIS and other project level EIR/EISs will examine a range of project alternatives for portions of the proposed HST system within corridors selected in the statewide program EIR/EIS, as well as a no action alternative. This and other project level EIR/EISs will fully describe site-specific environmental impacts and will identify specific mitigation measures to address those impacts and will incorporate design practices to avoid and minimize potential adverse environmental impacts. The FRA and the Authority will assess the site characteristics, size, nature, and timing of proposed site-specific projects to determine whether the impacts are potentially significant and whether impacts can be avoided or mitigated. This and other project EIR/EISs will identify and evaluate reasonable and feasible site-specific alignment alternatives, evaluate the impacts from construction, operation, and maintenance of the HST system, and identify mitigation measures. Information and documents regarding the HST environmental review process will be made available through the Authority's Internet site: *http://www.cahighspeedrail.gov/.*

Purpose and Need: The need for a HST system is directly related to the expected growth in population and increase in intercity travel demand in California over the next twenty years and beyond. With growth in travel demand, there will be an increase in travel delays arising from the growing congestion on California's highways and at airports. In addition, there will be negative effects on the economy, quality of life, and air quality in and around California's metropolitan areas from a transportation system that will become less reliable as travel demand increases. The intercity highway system, commercial airports, and conventional passenger rail serving the intercity travel market are currently operating at or near capacity, and will require large public investments for maintenance and expansion to meet existing demand and future growth. The purpose of the proposed HST system is to provide a new mode of high-speed intercity travel that would link the major metropolitan areas of the state; interface with international airports, mass transit, and highways; and provide added capacity to meet increases in intercity travel demand in California in a manner

sensitive to and protective of California's unique natural resources.

Alternatives: The Palmdale-Los Angeles HST EIR/EIS will consider a No Action or No Project Alternative and HST Alternatives for the Palmdale to Los Angeles corridor.

No Action Alternative: The take no action (No Project or No Build) alternative is defined to serve as the baseline for assessment of the HST Alternative. The No Build Alternative represents the region's transportation system (highway, air, and conventional rail) as it existed in 2006, and as it would exist after completion of programs or projects currently planned for funding and implementation by 2030. The No Build Alternative defines the existing and future intercity transportation system for the Palmdale to Los Angeles corridor based on programmed and funded improvements to the intercity transportation system through 2030, according to the following sources of information: State Transportation Improvement Program (STIP), Regional Transportation Plans (RTPs) for all modes of travel, airport plans, and intercity passenger rail plans.

HST Alternative: The Authority proposes to construct, operate and maintain an electric-powered steel-wheel-on-steel-rail HST system, over 700-mile long (1,126-kilometer long), capable of speeds in excess of 200 miles per hour (mph) (320 kilometers per hour [km/h]) on dedicated, fully grade-separated tracks, with state-of-the-art safety, signaling, and automated train control systems. The Palmdale to Los Angeles HST corridor that was selected by the Authority and FRA with the statewide program EIR/EIS follows SR–58/Soledad Canyon from the City of Palmdale to Sylmar and then along the Metrolink Railroad line to Los Angeles Union Station. The corridor is relatively wide in the area that includes both the SR–14 and Union Pacific Railroad alignments between the Antelope Valley and Santa Clarita. Further engineering studies to be undertaken as a part of this EIR/EIS process will examine and refine alignments in the selected corridor, including sections from the Palmdale to Santa Clarita and from the Burbank Metrolink Station to Los Angeles Union Station. An alignment option that closely follows the SR–14 through Soledad Canyon will be considered as well as an alignment option through Soledad Canyon along the Santa Clara River. Alignments along San Fernando Road adjacent to Taylor Yard and along the existing Metrolink right-of-way around the Taylor Yard area will be considered.

Station location options were selected by the Authority and FRA with the statewide program EIR/EIS considering travel time, train speed, cost, local access times, potential connections with other modes of transportation, ridership potential and the distribution of population and major destinations along the route, and local planning constraints/conditions. Alternative station sites at the selected general station locations will be identified and evaluated in this project level EIR/EIS. Station area development policies to encourage transit-friendly development near and around HST stations that would have the potential to promote higher density, mixed-use, pedestrian-oriented development around the stations will be prepared in coordination with local and regional planning agencies. Potential station locations to be evaluated in the Palmdale-Los Angeles HST EIR/EIS include: City of Palmdale, Palmdale Transportation Center; City of Sylmar, Sylmar Metrolink station; and City of Burbank, Burbank Metrolink station. The HST station at Los Angeles Union Station is being evaluated in the project level Los Angeles-Orange HST EIR/EIS and will not be considered in the Palmdale-Los Angeles HST EIR/EIS process. In addition, potential sites for turnback/layover train storage facilities and a main HST repair and heavy maintenance facility will be evaluated in the Palmdale-Los Angeles HST EIR/EIS.

Probable Effects: The purpose of the EIR/EIS process is to explore in a public setting the effects of the proposed project on the physical, human, and natural environment. The FRA and the Authority will continue the tiered evaluation of all significant environmental, social, and economic impacts of the construction and operation of the HST system. Impact areas to be addressed include: transportation impacts; safety and security; land use, and zoning; secondary development; land acquisition, displacements, and relocations; cultural resource impacts, including impacts on historical and archaeological resources and parklands/recreation areas; neighborhood compatibility and environmental justice; natural resource impacts including air quality, wetlands, water resources, noise, vibration, energy, wildlife and ecosystems, including endangered species. Measures to avoid, minimize, and mitigate all adverse impacts will be identified and evaluated.

Scoping and Comments: FRA encourages broad participation in the EIS process during scoping and review of the resulting environmental documents. Comments and suggestions are invited from all interested agencies and the public at large to insure the full range of issues related to the proposed action and all reasonable alternatives are addressed and all significant issues are identified. In particular, FRA is interested in determining whether there are areas of environmental concern where there might be a potential for significant impacts identifiable at a project level. Public agencies with jurisdiction are requested to advise FRA and the Authority of the applicable permit and environmental review requirements of each agency, and the scope and content of the environmental information that is germane to the agency's statutory responsibilities in connection with the proposed project. Public agencies are requested to advise FRA if they anticipate taking a major action in connection with the proposed project and if they wish to cooperate in the preparation of the project level EIR/EIS. Public scoping meetings have been scheduled as an important component of the scoping process for both the State and Federal environmental review. The scoping meetings described in this Notice will also be advertised locally and included in additional public notification.

Issued in Washington, DC, on March 9, 2007.

Mark E. Yachmetz,

Associate Administrator for Railroad Development.

[FR Doc. E7–4711 Filed 3–14–07; 8:45 am]

BILLING CODE 4910–06–P

DEPARTMENT OF TRANSPORTATION

Federal Transit Administration

Intent To Prepare an Environmental Impact Statement for High-Capacity Transit Improvements in the Leeward Corridor of Honolulu, HI

AGENCY: Federal Transit Administration, DOT.

ACTION: Notice of Intent to prepare an Environmental Impact Statement (EIS).

SUMMARY: The Federal Transit Administration (FTA) and the City and County of Honolulu, Department of Transportation Services (DTS) intend to prepare an EIS on a proposal by the City and County of Honolulu to implement a fixed-guideway transit system in the corridor between Kapolei and the University of Hawaiʻi at Mānoa with a branch to Waikīkī. Alternatives proposed to be considered in the draft

EIS include No Build and two Fixed Guideway Transit alternatives.

The EIS will be prepared to satisfy the requirements of the National Environmental Policy Act of 1969 (NEPA) and its implementing regulations. The FTA and DTS request public and interagency input on the purpose and need to be addressed by the project, the alternatives to be considered in the EIS, and the environmental and community impacts to be evaluated.

DATES: *Scoping Comments Due Date:* Written comments on the scope of the NEPA review, including the project's purpose and need, the alternatives to be considered, and the related impacts to be assessed, should be sent to DTS by April 12, 2007. See **ADDRESSES** below.

Scoping Meetings: Meetings to accept comments on the scope of the EIS will be held on March 28 and 29, 2007 at the locations given in **ADDRESSES** below. On March 28, 2007, the public scoping meeting will begin at 6:30 p.m. and continue until 9 p.m. or until all who wish to provide oral comments have been given the opportunity. The meeting on March 29, 2007 will begin at 5 p.m. and continue until 8 p.m. or until all who wish to provide oral comments have been given the opportunity. The locations are accessible to people with disabilities. A court reporter will record oral comments. Forms will be provided on which to submit written comments. Project staff will be available at the meeting to informally discuss the EIS scope and the proposed project. Governmental agencies will be invited to a separate scoping meeting to be held during business hours. Further project information will be available at the scoping meetings and may also be obtained by calling (808) 566–2299, by downloading from *http://www.honolulutransit.org,* or by e-mailing *info@honolulutransit.gov.*

ADDRESSES: Written comments on the scope of the EIS, including the project's purpose and need, the alternatives to be considered, and the related impacts to be assessed, should be sent to the Department of Transportation Services, City and County of Honolulu, 650 South King Street, 3rd Floor, Honolulu, HI 96813, Attention: Honolulu High-Capacity Transit Corridor Project, or by the Internet at *http://www.honolulutransit.org.*

The scoping meetings will be held at Kapolei Hale at 1000 Uluohia Street, Kapolei, HI 96707 on March 28, 2007 from 6:30 p.m. to 9 p.m. and at McKinley High School at 1039 South King Street, Honolulu, HI 9814 on March 29, 2007 from 5 p.m. to 8 p.m.

FOR FURTHER INFORMATION CONTACT: Ms. Donna Turchie, Federal Transit Administration, Region IX, 201 Mission Street, Room 1650, San Francisco, CA 94105, *Phone:* (415) 744–2737, *Fax:* (415) 744–2726.

SUPPLEMENTARY INFORMATION:

I. Background

On December 7, 2005, FTA and DTS issued a notice of intent to prepare an Alternatives analysis followed by a separate EIS. The TS has now completed the planning alternatives analysis and, together with FTA, is proceeding with the NEPA review initiated through this scoping notice.

The planning Alternatives analysis, conducted in accordance with 49 United States Code (U.S.C.) 5309 as amended by the Safe, Accountable, Flexible, Efficient Transportation Equity Act: A Legacy for Users (SAFETEA–LU) (Pub. L. 109–59, 119 Stat. 1144), evaluated transit alternatives in the corridor from Kapolei to the University of Hawai'i at Mānoa and to Waikīkī. Four alternatives were studied, including No build, Transportation system Management, Bus operating in a Managed Lane, and Fixed Guideway Transit. Fixed Guideway Transit was selected as the Locally Preferred Alternative. The planning Alternatives Analysis is available on the project's Web site at *http://www.honolulutransit.org.* The Honolulu City Council has established a fixed-guideway transit system connecting Kapolei and University of Hawai'i at Mānoa, with a branch to Waikīkī, as the locally preferred alternative. the O'ahu Metropolitan Planning Organization (OMPO) has included construction of rail transit system between Kapolei and the University of Hawai'i at Mānoa and Waikīkī in the 2030 O'ahu Regional Transportation Plan, April 2006.

II. Scoping

The FTA and DTS invite all interested individuals and organizations, and Federal, State, and local governmental agencies and Native Hawaiian organizations, to comment on the project's purpose and need, the alternatives to be considered in the EIS, and the impacts to be evaluated. During the scoping process, comments on the proposed statement of purpose and need should address its completeness and adequacy. Comments on the alternatives should propose alternatives that would satisfy the purpose and need at less cost or with greater effectiveness or less environmental or community impact and were not previously studied and eliminated for good cause. At this time, comments should focus on the scope of the NEPA review and should not state a preference for a particular alternative. The best opportunity for that type of input will be after the release of the draft EIS.

Following the scoping process, public outreach activities with interested parties or groups will continue throughout the duration of work on the EIS. The project Web site, *http://www.honolulutransit.org,* will be updated periodically to reflect the status of the project. Additional Opportunities for public participation will be announced through mailings, notices, advertisements, and press releases. those wishing to be placed on the project mailing list may do so by registering on the Web site at *http://www.honolulutransit.org,* or by calling (808) 566–2299.

III. Description of Study Area

The proposed project study area is the travel corridor between Kapolei and the University of Hawai'i at Mānoa (UH Mānoa) and Waikākī. this narrow, linear corridor is confined by the Wai'anae and Ko'olau mountain ranges to the north (mauka direction) and the ocean to the south (makai direction). The corridor includes the majority of housing and employment on O'ahu. The 2000 census indicates that 876,200 people live on O'ahu. Of this number, over 552,000 people, or 63 percent, live within the corridor between Kapolei and Mānoa/Waikīkī. This area is projected to absorb 69 percent of the population growth projected to occur on O'ahu between 2000 and 2030, resulting in an expected corridor population of 776,000 by 2030. Over the next twenty-three years, the 'Ewa/Kapolei area is projected to have the highest rate of housing and employment growth on O'ahu. The 'Ewa/Kapolei area is developing as a ''second city'' to complement downtown Honolulu. The housing and employment growth in 'Ewa is identified in the General Plan for the City and County of Honolulu.

IV. Purpose and Need

The purpose of the Honolulu High-Capacity Transit Corridor Project is to provide high-capacity, high-speed transit in the highly congested east-west transportation corridor between Kapolei and the University of Hawai'i at Mānoa, as specified in the 2030 O'ahu Regional Transportation Plan (ORTP). The project is intended to provide faster, more reliable public transportation services in the corridor than those currently operating in mixed-flow traffic, to

provide basic mobility in areas of the corridor where people of limited income live, and to serve rapidly developing areas of the corridor. The project would also provide an alternative to provide automobile travel and improve transit linkages within the corridor. Implementation of the project, in conjunction with other improvements included in the ORTP, would moderate anticipated traffic congestion in the corridor. The project also supports the goals of the O'ahu General Plan and the ORTP by serving areas designated for urban growth.

The existing transportation in infrastructure in the corridor between Kapolei and UH Mānoa is overburdened handling current levels of travel demand. Motorists and transit users experience substantial traffic congestion and delay at most times of the day, both on weekdays and on weekends. Average weekly peak-period speeds on the H–1 Freeway are currently less than 20 mph in many places and will degrade even further by 2030. Transit vehicles are caught in the same congestion. Travelers on O'ahu's roadways currently experience 51,000 vehicle hours of delay, a measure of how much time is lost daily by travelers stuck in traffic, on a typical weekday. This measure of delay is projected to increase to more than 71,000 daily vehicle hours of delay by 2030, assuming implementation of all the planned improvements listed in the ORTP (except for a fixed guideway system). Without these improvements, ORTP indicates that daily vehicle-hours of delay could increase to as much as 326,000 vehicle hours.

Currently, motorists traveling from West O'ahu to Downtown Honolulu experience highly congested traffic conditions during the a.m. peak period. By 2030, after including all of the planned roadway improvements in the ORTP, the level of congestion and travel time are projected to increase further. Average bus speeds in the corridor have been decreasing steadily as congestion has increased. ''TheBus'' travel times are projected to increase substantially through 2030. Within the urban core, most major arterial streets will experience increasing peak-period congestion, including Ala Moana Boulevard, Dillingham Boulevard, Kalākaua Avenue, Kapi'olani Boulevard, King Street, and Nimitz Highway. Expansion of the roadway system between Kapolei and UH Mānoa is constrained by physical barriers and by dense urban neighborhoods that abut many existing roadways. Given the current and increasing levels of congestion, a need exists to offer an alternative way to travel within the corridor independent of current and projected highway congestion.

As roadways become more congested, they become more susceptible to substantial delays caused by incidents, such as traffic accidents or heavy rain. Even a single driver unexpectedly braking can have a ripple effect delaying hundreds of cars. Because of the operating conditions in the study corridor, current travel times are not reliable for either transit or automobile trips. To get to their destination on time, travelers must allow extra time in their schedules to account for the uncertainty of travel time. This lack of predictability is inefficient and results in lost productivity. Because the bus system primarily operates in mixed-traffic, transit users experience the same level of travel time uncertainty as automobile users. A need exists to reduce transit travel times and provide a more reliable transit system.

Consistent with the General Plan for the City and County of Honolulu, the highest population growth rates for the island are projected in the 'Ewa Development Plan area (comprised of the 'Ewa, Kapolei and Makakilo communities), which is expected to grow by 170 percent between 2000 and 2030. This growth represents nearly 50 percent of the total growth projected for the entire island. The more rural areas of Wai'anae, Wahiawā, North Shore, Waimānalo, and East Honolulu will have lower population growth of between zero and 16 percent if infrastructure policies support the planned growth in the 'Ewa Development Plan area. Kapolei, which is developing as a ''second city'' to Downtown Honolulu, is projected to grow by nearly 600 percent is 81,100 people, the 'Ewa neighborhhood by 100 percent, and Makakilo by 125 percent between 2000 and 2030. Accessibility to the overall 'Ewa Development Plan area is currently severely impaired by the congested roadway network, which will only get worse in the future. This area is less likely to develop as planned unless it is accessible to Downtown and other parts of O'ahu; therefore, the 'Ewa, Kapolei, and Makakilo area needs improved accessibility to support its future growth as planned.

Many lower-income and minority workers live in the corridor outside of the urban core and commute to work in the Primary Urban Center Development Plan area. Many lower-income workers also rely on transit because of its affordability. In addition, daily parking costs in Downtown Honolulu are among the highest in the United States, further limiting this population's access to Downtown. Improvements to transit capacity and reliability will serve all transportation system users, including moderate- and low-income populations.

V. Alternatives

The alternatives proposed for evaluation in the EIS were developed through a planning Alternatives Analysis that resulted in selection of a Fixed Guideway Transit Alternative as the locally preferred alternative (LPA). FTA and DTS propose to consider the following alternatives:

• Future No Build Alternative, which would include existing transit and highway facilities and planned transportation projects (excluding the proposed project) anticipated to be operational by the year 2030. Bus service levels consistent with existing transit service policies is assumed for all areas within the project corridor under the Future No Build Alternative.

• Fixed Guideway Alternatives, which would include the construction and operation of a fixed guideway transit system in the corridor between Kapolei and UH Mānoa with a branch to Waikīkī. The draft EIS would consider five distinct transit technologies: Light trail transit, rapid rail transit, rubber-tired guided vehicles, a magnetic levitation system, and a monorail system. Comments on reducing the range of technologies under consideration are encouraged. The draft EIS also would consider two alignment alternatives. Both alignment alternatives would operate, for the most part, on a transit-guideway structure elevated above the roadway, with some sections at grade. Both alignment alternatives generally follow the route: North-South Road to Farrington Highway/Kamehameha Highway to Salt Lake Boulevard to Dillingham Boulevard to Nimitz Highway/Halekauwila Street. Both alignment alternatives would have a future extension from downtown Honolulu to UH Mānoa with a future branch to Waikīkī, and a future extension at the Waianae (western) end to Kalaeloa Boulevard in Kapolei. The second alignment alternative would have an additional loop created by a fork in the alignment at Aloha Stadium to serve Honolulu International Airport that rejoins the main alignment in the vicinity of the Middle Street Transit Center. The first construction phase for either of the Fixed Guideway Alternatives is currently expected to begin in the vicinity of the planned University of Hawai'i West O'ahu campus and extend to Ala Moana Center via Salt Lake Boulevard. The Build alternatives also include the construction of a vehicle maintenance

facility, transit stations and ancillary facilities such as park-and-ride lots and traction-power substations, and the modification and expansion of bus service to maximize overall efficiency of transit operation.

Other reasonable alternatives suggested during the scoping process may be added if they were not previously evaluated and eliminated for good cause on the basis of the Alternatives Analysis and are consistent with the project's purpose and need. The planning Alternatives Analysis is available for public and agency review on the project Web site at *http://www.honolulutransit.org*. It is also available for inspection at the project office by calling (808) 566–2299 or by e-mailing *info@honolulutransit.org*.

VI. Probable Effects

The EIS will evaluate and fully disclose the environmental consequences of the construction and operation of a fixed guideway transit system on O'ahu. The EIS will evaluate the impacts of all reasonable alternatives on land use, zoning, residential and business displacements, parklands, economic development, community disruptions, environmental justice, aesthetics, noise, wildlife, vegetation, endangered species, farmland, water quality, wetlands, waterways, floodplains, hazardous waste materials, and cultural, historic, and archaeological resources. To ensure that all significant issues related to this proposed action are identified and addressed, scoping comments and suggestions on more specific issues of environmental or community impact are invited from all interested parties. Comments and questions should be directed to the DTS as noted in the **ADDRESSES** section above.

VII. FTA Procedures

The EIS will be prepared in accordance with the National Environmental Policy Act of 1969 (NEPA), as amended, and its implementing regulations by the Council on Environmental Quality (CEQ) (40 CFR parts 1500–1508) and by the FTA and Federal Highway Administration (''Environmental Impact and Related Procedures'' at 23 CFR part 771). In accordance with FTA regulation and policy, the NEPA process will also address the requirements of other applicable environmental laws, regulations, and executive orders, including, but not limited to: Federal transit laws [49 U.S.C. 5301(e), 5323(b), and 5324(b)], Section 106 of the National Historic Preservation Act, Section 4(f) (''Protection of Public Lands'') of the U.S. Department of Transportation Act (49 U.S.C. 303), Section 7 of the Endangered Species Act, and the Executive Orders on Environmental Justice, Floodplain Management, and Protection of Wetlands.

Dated: March 12, 2007.

Leslie T. Rogers,

Regional Administrator.

[FR Doc. 07–1237 Filed 3–14–07; 8:45 am]

BILLING CODE 4910–57–M

DEPARTMENT OF TRANSPORTATION

Maritime Administration

[USCG–2004–16877]

Cabrillo Port Liquefied Natural Gas Deepwater Port License Application; Final Public Hearing and Final Environmental Impact Statement/Final Environmental Impact Report

AGENCY: Maritime Administration, DOT.

ACTION: Notice of availability; notice of public hearing; request for comments.

SUMMARY: The Maritime Administration (MARAD) and the U.S. Coast Guard (USCG) announce the availability of the Final Environmental Impact Statement/Environmental Impact Report (FEIS/FEIR) for the Cabrillo Port Liquefied Natural Gas (LNG) Deepwater Port (DWP) license application. In addition, a public hearing will be held regarding the approval or denial of the license application. The proposed Cabrillo Port LNG DWP would be located offshore of Ventura County, California. Since the applicant has also filed a California State Lands Commission (CSLC) land lease application for subsea pipelines through California State waters to deliver natural gas to shore, the FEIS/FEIR was prepared in accordance with a Memorandum of Agreement with the CSLC. The FEIS/FEIR meets requirements consistent with the Deepwater Port Act (DWPA) of 1974, as amended (33 U.S.C. 1501 *et seq.*); the National Environmental Policy Act (NEPA Section 102[2][3]), as implemented by Council on Environmental Quality regulations (40 Code of Federal Regulations 1500 to 1508); and the California Environmental Quality Act (CEQA) (California Public Resources Code Section 21000 *et seq.*). The USCG and MARAD will receive public comments on the FEIS/FEIR and license application. Publication of this notice begins a 45 day comment period and provides information on how to participate in the process.

DATES: The FEIS/FEIR will be available on March 16, 2007. Material submitted in response to the request for comments on the FEIS/FEIR and application must reach the Docket Management Facility by April 30, 2007 ending the 45 day public comment period. The final public hearing will be held in Oxnard, CA on April 4, 2007, from 5 p.m. to 8 p.m. and will be preceded by an informational open house from 3 p.m. to 4:30 p.m. The public hearing may end later than the stated time, depending on the number of persons wishing to speak.

Federal and State agencies must submit comments, recommended conditions for licensing, or letters of no objection by May 21, 2007 (45 days after the final public hearing). In addition, by that same date, May 21, 2007, the Governor of California (the adjacent coastal state) may approve, disapprove, or notify MARAD of inconsistencies with State programs relating to environmental protection, land and water use, and coastal zone management for which MARAD may condition the license to make consistent with such State programs.

MARAD must issue a record of decision (ROD) to approve, approve with conditions, or deny the DWP license application by July 3, 2007 (90 days after the public hearing).

ADDRESSES: The USCG and MARAD will conduct a public hearing in Oxnard to receive oral or written comments on April 4, 2007 from 5 p.m. to 8 p.m. at the Performing Arts and Convention Center, Oxnard Room, 800 Hobson Way, Oxnard, California, 93030, telephone: (805) 486–2424.

The public meeting space will be wheelchair-accessible. Individuals may request special accommodations for the public hearing, such as real time Spanish translation and/or for the hearing impaired. Contact Raymond Martin, USCG, at 202–372–1449 *Raymond.W.Martin@uscg.mil* if special accommodations are required. Requests should be made as soon as possible but at least three (3) business days before the scheduled meeting. Include the name and telephone number of the contact person, the timelines for requesting accommodations, and a TDD number that can be used by individuals with hearing impairments.

The FEIS/FEIR, the application, comments and associated documentation are available for viewing at the DOT's Docket Management System Web site: *http://dms.dot.gov* under docket number 16877. The FEIS/FEIR is also available at public libraries in Oxnard (Albert H. Soliz Library and Main Library, Oxnard Public Libraries),

Port Hueneme (Ray D. Prueter Library), Valencia (Valencia Library), and Malibu (Malibu Community Library).

Address docket submissions for USCG–2004–16877 to: Docket Management Facility, U.S. Department of Transportation, 400 Seventh Street, SW., Washington, DC 20590–0001.

The Docket Management Facility accepts hand-delivered submissions, and makes docket contents available for public inspection and copying at this address, in room PL–401, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The Facility's telephone number is 202–366–9329, its fax number is 202–493–2251, and its web site for electronic submissions or for electronic access to docket contents is *http://dms.dot.gov*.

FOR FURTHER INFORMATION CONTACT: Information pertaining to the proposed Cabrillo Port Project is available online at *http://dms.dot.gov*, or *http://www.slc.ca.gov*. Questions regarding the proposed Project, the license application process, or the FEIS/FEIR process may be directed to Raymond Martin, U.S. Coast Guard, telephone: 202–372–1449, e-mail: *Raymond.W.Martin@uscg.mil,* or Keith Lesnick, MARAD, (202) 366–1624, e-mail: *Keith.Lesnick@dot.gov*.

If you have questions on viewing the docket, call Renee V. Wright, Program Manager, Docket Operations, telephone: 202–493–0402.

This public notice may be requested in an alternative format, such as Spanish translation, audiotape, large print, or Braille. Contact Raymond Martin, USCG, telephone: 202–372–1449, e-mail: *Raymond.W.Martin@uscg.mil* or visit *http://www.cabrilloport.ene.com*.

SUPPLEMENTARY INFORMATION:

Public Hearing and Open House

We invite you to learn about the proposed deepwater port at an informational open house, and to comment at a public hearing on the proposed action and the evaluation contained in the FEIS/FEIR. In order to allow all interested parties an opportunity to speak at the public hearing, we may limit speaker time, or extend the hearing hours, or both. You must identify yourself, and any organization you represent, by name. Your remarks will be recorded or transcribed for inclusion in the public docket. Additionally, written comments may be submitted at the open house or public hearing and a court reporter will be available to take comments during the open house for those wishing to make oral comments.

You may submit written material at the public hearing, either in place of or in addition to speaking. Written material must include your name and address, and will be included in the public docket.

Public docket materials will be made available to the public on the DOT Docket Management System (DMS). See ''Request for Comments'' for information about DMS and your rights under the Privacy Act.

Request for Comments

We will receive public comments or other relevant information on the FEIS/FEIR and application. The public hearing is not the only opportunity you have to comment. In addition to or in place of attending a hearing, you can submit comments to the Docket Management Facility during the public comment period (see **DATES**). The Coast Guard and MARAD will consider all relevant comments and materials received during the comment period.

Submissions should include:

• Docket number USCG–2004–16877.

• Your name and address.

• Your reasons for making each comment or for bringing information to our attention.

Submit comments or material using only one of the following methods:

• Electronic submission to DMS, *http://dms.dot.gov*.

• Fax, mail, or hand delivery to the Docket Management Facility (see **ADDRESSES**). Faxed or hand delivered submissions must be unbound, no larger than 8½ by 11 inches, and suitable for copying and electronic scanning. If you mail your submission and want to know when it reaches the Facility, include a stamped, self-addressed postcard or envelope.

Privacy Act

Regardless of the method used for submitting comments or material, submissions will be posted, without change, to the DMS Web site (*http://dms.dot.gov*), and will include any personal information you provide. Therefore, submitting this information makes it public. You may wish to read the Privacy Act notice that is available on the DMS website, or the Department of Transportation Privacy Act Statement that appeared in the **Federal Register** on April 11, 2000 (65 FR 19477).

You may view docket submissions at the Docket Management Facility (see **ADDRESSES**), or electronically on the DMS Web site.

Background

We published the Notice of Application for the proposed Cabrillo Port LNG deepwater port and information on regulations and statutes governing the license review process in the **Federal Register** at 69 FR 3934, January 27, 2004; the Notice of Intent to Prepare a joint EIS/EIR for the proposed action was published at 69 FR 9344, February 27, 2004; and the Notice of Availability of the Draft EIS/EIR was published at 69 FR 64578, November 5, 2004. Additionally, the State of California determined it was necessary to recirculate the Draft EIR due to several changes in the project. A Revised Draft EIR was published in March 2006. Information from the ''Summary of the Application'' from previous **Federal Register** notices is included below for your convenience.

Proposed Action

The proposed action requiring review is the Federal licensing of the proposed deepwater port described in ''Summary of the Application'' below. The actions available to MARAD are: (1) License the port with conditions (including conditions designed to mitigate environmental impact), or (2) deny the license, which for purposes of environmental review is the ''no-action'' alternative. These potential actions are more fully discussed in the FEIS/FEIR. The USCG and MARAD are the lead Federal agencies for the preparation of the EIS/EIR. You can address any questions about the proposed action or the FEIS/FEIR to the USCG project manager identified in **FOR FURTHER INFORMATION CONTACT**.

Summary of the Application

The Applicant proposes to construct and operate an offshore floating storage and regasification unit (FSRU) that would be moored in Federal waters approximately 12.01 nautical miles (13.83 statute miles or 22.25 kilometers) offshore of Ventura County in 2,900 feet (884 meters) of water. As proposed, LNG from the Pacific basin would be delivered to and offloaded from an LNG carrier onto the FSRU; re-gasified; and the natural gas would be delivered onshore via two 24 inch (0.6 meters) diameter natural gas pipelines totaling approximately 22.77 statute miles (36.64 kilometers) laid on the ocean floor. These pipelines would come onshore at Ormond Beach near Oxnard, California to connect with the existing Southern California Gas Company intrastate pipeline system to distribute natural gas throughout the Southern California region. The facilities would be designed to deliver an annual average of up to 0.8 billion cubic feet per day (bcfd) (22.7 million cubic meters per day) and peak

delivery capacity of 1.5 bcfd (42.5 million cubic meters per day).

The FSRU would store LNG in three Moss spherical tanks. Each tank would have a 24 million gallon (90,800 cubic meters) LNG storage capacity, and the total FSRU LNG storage capacity would be approximately 72 million gallons (273,000 cubic meters). The FSRU would be permanently moored, and would use a turret system (a tower-like revolving structure) to allow the FSRU to weathervane (rotate) around a fixed point. A Safety Zone would be established covering a 500-meter (1,640-foot) radius out from the stern of the FSRU. The FSRU, which would be designed for loading LNG from side-by-side, moored LNG tankers, would be shaped like a double-sided, double-bottomed vessel, 971 feet (296 meters) long and 213 feet (65 meters) wide, with a displacement of approximately 190,000 deadweight tons.

Alternatives

The FEIS/FEIR examines and assesses the environmental impact of the project location and pipeline routes of the proposed action, alternatives, and the no-action alternative. In addition to the environmental impacts, the FEIS/FEIR considers approving, approving with conditions or denying (no action alternative) the application for a license.

Dated: March 9, 2007.

By Order of the Maritime Administrator.

Daron T. Threet,

Secretary, Maritime Administration.

[FR Doc. E7–4767 Filed 3–14–07; 8:45 am]

BILLING CODE 4910–81–P

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

Hazardous Materials: Improving the Safety of Railroad Tank Car Transportation of Hazardous Materials

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), DOT.

ACTION: Notice of public meeting.

SUMMARY: As part of PHMSA's and the Federal Railroad Administration's (FRA) comprehensive review of design and operational factors that affect the safety of railroad tank car transportation of hazardous materials, the two agencies invite interested persons to participate in a public meeting addressing potential improvements to hazardous materials tank cars in order to improve the overall safety of hazardous materials shipments via railroad tank car.

DATES: *Public meeting:* March 30, 2007, starting at 9 a.m.

ADDRESSES: *Public meeting:* The meeting will be held at The Westin O'Hare, 6100 River Road, Rosemont, Illinois 60018. For information on the facilities or to request special accommodations at the meeting, please contact Ms. Michele M. Sampson by telephone or e-mail as soon as possible.

Written Comments: Written comments may be submitted identified by DOT DMS Docket Number FRA–2006–25169 by any of the following methods:

- *Web site: http://dms.dot.gov.* Follow the instructions for submitted comments on the DOT electronic docket site.
- *Fax:* 1–202–493–2251.
- *Mail:* Docket Management Facility; U.S. Department of Transportation, 400 Seventh Street, SW., Nassif Building, Room PL–401, Washington, DC 20590.
- *Hand Delivery:* Room PL–401 on the plaza level of the Nassif Building, 400 Seventh Street, SW., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: Michele M. Sampson (*Michele.Sampson@dot.gov*), Railroad Safety Specialist, Federal Railroad Administration, 1120 Vermont Ave., NW., Washington, DC 20590 (202–493–6475) or Lucinda Henriksen (*Lucinda.Henriksen@dot.gov*), Trial Attorney, Office of Chief Counsel, Federal Railroad Administration, 1120 Vermont Ave., NW., Washington, DC 20590 (202–493–1345).

SUPPLEMENTARY INFORMATION: The Federal hazardous materials transportation law (Federal hazmat law, 49 U.S.C. 5101 *et seq.*, as amended by section 1711 of the Homeland Security Act of 2002, Public Law 107–296 and Title VII of the 2005 Safe, Accountable, Flexible and Efficient Transportation Equity Act—A Legacy for Users (SAFETEA–LU)) authorizes the Secretary of the Department of Transportation (DOT) to ''prescribe regulations for the safe transportation, including security, of hazardous material in intrastate, interstate, and foreign commerce.'' The Secretary has delegated this authority to PHMSA.

The Secretary of Transportation also has authority over all areas of railroad safety (49 U.S.C. 20101 *et seq.*), and has delegated this authority to FRA. FRA has issued a comprehensive set of Federal regulations governing the safety of all facets of freight and passenger railroad operations (49 CFR parts 200–244). FRA inspects railroads and shippers for compliance with both FRA and PHMSA regulations. FRA also conducts research and development to enhance railroad safety.

On May 24, 2006, PHMSA and FRA announced that the two operating administrations of the DOT were initiating a comprehensive review of design and operational factors that affect the safety of railroad tank car transportation of hazardous materials. 71 FR 30019. In order to facilitate public involvement in this review, FRA established a public docket (docket no. FRA–2006–25169) to provide interested parties with a central location to both send and review relevant information concerning the safety of railroad tank car transportation of hazardous materials. *See* 71 FR 37974 (July 3, 2006). In addition, PHMSA and FRA held public meetings on May 31–June 1, 2006 and on December 14, 2006 (see 71 FR 30019 and 71 FR 67015 (Nov. 17, 2006)). The primary purpose of the first meeting was to surface and prioritize issues relating to the safe and secure transportation of hazardous materials by railroad tank car. The primary purpose of the second meeting was to solicit input and comments in response to specific questions posed by the agencies. In addition, at the December meeting, FRA announced the agency's commitment to develop an enhanced tank car standard by 2008.

This document announces that PHMSA and FRA have scheduled a third public meeting as part of DOT's comprehensive review. The meeting will be held on the date specified in the **DATES** section of this document and at the location specified in the **ADDRESSES** section of this document. At this meeting, FRA intends to share its preliminary research results regarding tank car survivability and provide an update on the agency's progress towards developing an enhanced tank car standard. FRA also invites interested parties to participate in the meeting by presenting any relevant comments, information, or data, regarding potential enhancements or modifications to hazardous materials tank cars in order to improve the overall safety and security of hazardous material shipments via railroad tank car. As with the previous public meetings, although DOT's review includes both tank car design and operational factors that affect railroad tank car safety, this public meeting is intended to focus on the issue of potential improvements to hazardous materials tank cars themselves. In order to facilitate discussion, FRA will post the materials to be presented at this meeting in the docket established for this proceeding (Docket Number FRA–2006–25169) by March 23, 2007. We encourage

interested parties to review the posted materials prior to the meeting.

PHMSA and FRA encourage all interested persons to participate in this meeting. The agencies ask that commenters provide data in the most detail possible, including costs of design, installation, and maintenance.

The agencies also invite interested parties who are unable to attend the public meeting, or who otherwise desire to submit written comments or data responsive to the questions raised above, to submit any relevant information, data, or comments to the DOT Docket Management System Docket Number FRA–2006–25169. Comments may be submitted by any method noted in the **ADDRESSES** section above.

Issued in Washington, DC on March 9, 2007, under authority delegated in 49 CFR part 106.

Robert Richard,

Acting Associate Administrator for Hazardous Materials Safety.

[FR Doc. E7–4686 Filed 3–14–07; 8:45 am]

BILLING CODE 4910–60–P

DEPARTMENT OF TRANSPORTATION

Surface Transportation Board

[STB Ex Parte No. 670]

Establishment of the Rail Energy Transportation Advisory Committee

AGENCY: Surface Transportation Board, DOT.

ACTION: Notice.

SUMMARY: The Surface Transportation Board seeks public comment on the desirability of establishing, pursuant to the Federal Advisory Committee Act (FACA), a Rail Energy Transportation Advisory Committee, to provide independent advice and policy suggestions to the Board on issues related to the reliability of rail transportation of resources critical to the nation's energy supply, including, but not necessarily limited to, the rail transportation of coal and ethanol. Specifically, the Board seeks the views of interested persons on the utility of establishing such a committee, and, if established, the appropriate scope and the optimum size and composition of such a committee so as to reflect an appropriate and balanced cross-section of interested and affected stakeholders.

DATES: Comments are due by April 16, 2007.

ADDRESSES: Comments may be submitted either via the Board's e-filing format or in the traditional paper format. Any person using e-filing should comply with the instructions at the E–FILING link on the Board's Web site, at *http://www.stb.dot.gov*. Any person submitting a filing in the traditional paper format should send an original and 10 copies to: Surface Transportation Board, Attn: STB Ex Parte No. 670, 395 E Street, SW., Washington, DC 20423–0001.

Copies of written comments will be available from the Board's contractor, ASAP Document Solutions (mailing address: Suite 103, 9332 Annapolis Rd., Lanham, MD 20706; e-mail address: *asapdc@verizon.net;* telephone number: 202–306–4004). The comments will also be available for viewing and self-copying in the Board's Public Docket Room, Room 131, and will be posted to the Board's Web site at *http://www.stb.dot.gov*.

FOR FURTHER INFORMATION CONTACT: Scott M. Zimmerman at 202–245–0202. [Assistance for the hearing impaired is available through the Federal Information Relay Service (FIRS) at 1–800–877–8339.]

SUPPLEMENTARY INFORMATION: The Surface Transportation Board (STB or Board) is seeking public comment on issues relating to the potential establishment of a federal advisory committee to provide independent advice and policy recommendations to the Board on issues pertaining to the reliability of rail transportation of energy resources, particularly, but not necessarily limited to, the rail transportation of coal and ethanol.

The Board, created by Congress in 1996 to take over many of the functions previously performed by the Interstate Commerce Commission, exercises broad authority over transportation by rail carriers, including regulation of railroad rates and service (49 U.S.C. 10701–10747, 11101–11124), as well as the construction, acquisition, operation, and abandonment of rail lines (49 U.S.C. 10901–10907) and railroad line sales, consolidations, mergers, and common control arrangements (49 U.S.C. 10902, 11323–11327).

The Board views the reliability of the nation's energy supply as crucial to this nation's economic and national security, and the transportation by rail of coal and other energy resources as a vital link in the energy supply chain. Particularly in the present environment of constrained rail capacity, the Board believes that an advisory committee consisting of a balanced cross-section of energy and rail industry stakeholders could serve as an important resource for providing independent, candid policy advice to the Board and for fostering open, effective communication among the affected interests on issues such as rail performance, capacity constraints, infrastructure planning and development, and effective coordination among suppliers, carriers, and users of energy resources.

The Board seeks input from interested persons on a number of issues, including: (1) What are the views of rail and energy industry stakeholders as to the potential utility of such a committee? (2) What would be the appropriate scope of such a committee's mandate—i.e., should it be limited to issues involving transportation of coal and ethanol, or constituted more broadly to include, for example, the biofuel industry and/or others? How would the scope of the committee's mandate affect its utility? (3) Consistent with one's views on the answers to the previous questions, what would be the optimum size of such a committee, and how should the committee's membership be allocated among various stakeholder groups to achieve a fairly balanced ''cross section of those directly affected, interested, and qualified,'' as required under the Federal Advisory Committee Act (FACA)?[1]

The Board is not, by this notice, establishing such a committee. Rather, it seeks from interested persons input that would assist the Board at this preliminary stage in developing a proposed charter for such an advisory committee, in consultation with the General Services Administration's Committee Management Secretariat, as provided under FACA.[2]

This action will not significantly affect either the quality of the human environment or the conservation of energy resources.

Authority: 49 U.S.C. 721, 49 U.S.C. 11101; 49 U.S.C. 11121.

Decided: March 9, 2007.

By the Board, Chairman Nottingham, Vice Chairman Buttrey, and Commissioner Mulvey.

Vernon A. Williams,

Secretary.

[FR Doc. E7–4769 Filed 3–14–07; 8:45 am]

BILLING CODE 4915–01–P

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[1] *See* 41 CFR 102–3.60(b)(3).

[2] *See* 41 CFR 102–3.60(a).

DEPARTMENT OF TRANSPORTATION

Surface Transportation Board

[STB Finance Docket No. 35002]

Savage Bingham & Garfield Railroad Company—Acquisition and Operation Exemption—Union Pacific Railroad Company

Savage Bingham & Garfield Railroad Company (SBGR), a noncarrier, has filed a verified notice of exemption under 49 CFR 1150.31 to acquire from Union Pacific Railroad Company (UP) and to operate freight easements upon, over, and across: (a) UP's lines of railroad between milepost 4.66 at Welby and milepost 17.10 at Magna (Garfield Branch), and between milepost 0.00 at Kearns and milepost 2.01 at Bacchus (Bacchus Branch); (b) the UP line of railroad between milepost 0.18 at Midvale and milepost 6.60 at Bagley Spur (Bingham Industrial Lead); and (c) various UP wye, yard and team tracks in the vicinity of Midvale (Midvale Trackage), a total of 20.87 miles, all in Salt Lake County, UT.

SBGR states that it will enter into a freight operating agreement and related agreements with UP governing SBGR's operations over the Bacchus Branch, the Garfield Branch and the Midvale Trackage. In addition, as a result of a separate transaction between the Utah Transit Authority (UTA) and UP, UP will: (a) Convey the right-of-way of the Bingham Industrial Lead to UTA; (b) reserve an operating easement over the Bingham Industrial Lead; and (c) convey such operating easement to SBGR. SBGR will enter into an administration and coordination agreement with UTA governing the provision of rail services by SBGR over the Bingham Industrial Lead during specified time separated periods when the planned UTA passenger light rail services are not in operation. UP and SBGR will interchange traffic at UP's Roper, UT rail yard.

SBGR certifies that its projected annual revenues as a result of the transaction will not result in the creation of a Class II or Class I rail carrier and will not exceed $5 million.

The earliest this transaction may be consummated is the March 29, 2007 effective date of the exemption (30 days after the exemption was filed).

If the verified notice contains false or misleading information, the exemption is void *ab initio*. Petitions to revoke the exemption under 49 U.S.C. 10502(d) may be filed at any time. The filing of a petition to revoke will not automatically stay the transaction. Petitions for stay must be filed no later than March 22, 2007 (at least 7 days before the exemption becomes effective).

An original and 10 copies of all pleadings, referring to STB Finance Docket No. 35002, must be filed with the Surface Transportation Board, 395 E Street, SW., Washington, DC 20423–0001. In addition, a copy of each pleading must be served on Robert P. vom Eigen, 3000 K Street, NW., Washington, DC 20007.

Board decisions and notices are available on our Web site at *http://www.stb.dot.gov*.

Decided: March 7, 2007.

By the Board, David M. Konschnik, Director, Office of Proceedings.

Vernon A. Williams,

Secretary.

[FR Doc. E7–4514 Filed 3–14–07; 8:45 am]

BILLING CODE 4915–01–P

DEPARTMENT OF TRANSPORTATION

Surface Transportation Board

[STB Docket No. AB–290 (Sub–No. 292X)]

Norfolk Southern Railway Company—Discontinuance Exemption—in Mahoning County, OH

Norfolk Southern Railway Company (NSR) has filed a verified notice of exemption under 49 CFR 1152 Subpart F—*Exempt Abandonments and Discontinuances of Service* to discontinue service over a 15.70-mile line of railroad between milepost RZ 20.20 near North Jackson and milepost RZ 35.90 near Sebring, in Mahoning County, OH. The line traverses United States Postal Service Zip Codes 44451, 44609, and 44672, and includes the stations of Ellsworth, Berlin Center, Berl, Snodes, Ring, and N. Sebring.

UP has certified that: (1) No traffic has moved over the line for at least 2 years; (2) all overhead traffic has been rerouted over other lines; (3) no formal complaint filed by a user of rail service on the line (or by a state or local government entity acting on behalf of such user) regarding cessation of service over the line either is pending with the Board or with any U.S. District Court or has been decided in favor of complainant within the 2-year period; and (4) the requirements at 49 CFR 1105.12 (newspaper publication) and 49 CFR 1152.50(d)(1) (notice to governmental agencies) have been met.

As a condition to this exemption, any employee adversely affected by the discontinuance of service shall be protected under Oregon Short Line R. Co.—Abandonment—Goshen, 360 I.C.C. 91 (1979). To address whether this condition adequately protects affected employees, a petition for partial revocation under 49 U.S.C. 10502(d) must be filed.

Provided no formal expression of intent to file an offer of financial assistance (OFA) has been received, this exemption will be effective on April 14, 2007, unless stayed pending reconsideration. Petitions to stay that do not involve environmental issues and formal expressions of intent to file an OFA for continued rail service under 49 CFR 1152.27(c)(2),[1] must be filed by March 26, 2007.[2] Petitions to reopen must be filed by April 4, 2007, with the Surface Transportation Board, 395 E Street, SW., Washington, DC 20423–0001.

A copy of any petition filed with the Board should be sent to NSR's representative: James R. Paschall, Senior General Attorney, Norfolk Southern Railway Company, Three Commercial Place, Norfolk, VA 23510.

If the verified notice contains false or misleading information, the exemption is void *ab initio*.

Board decisions and notices are available on our Web site at *http://www.stb.dot.gov*.

Decided: February 28, 2007.

By the Board, David M. Konschnik, Director, Office of Proceedings.

Vernon A. Williams,

Secretary.

[FR Doc. E7–4422 Filed 3–14–07; 8:45 am]

BILLING CODE 4915–01–P

DEPARTMENT OF THE TREASURY

Submission for OMB Review; Comment Request

March 9, 2007.

The Department of Treasury has submitted the following public information collection requirement(s) to OMB for review and clearance under the Paperwork Reduction Act of 1995, Public Law 104–13. Copies of the submission(s) may be obtained by calling the Treasury Bureau Clearance Officer listed. Comments regarding this information collection should be addressed to the OMB reviewer listed and to the Treasury Department Clearance Officer, Department of the

[1] Each OFA must be accompanied by the filing fee, which currently is set at $1,300. *See* 49 CFR 1002.2(f)(25).

[2] Because this is a discontinuance proceeding and not an abandonment, trail use/rail banking and public use conditions are not appropriate. Likewise, no environmental or historical documentation is required here under 49 CFR 1105.6(c) and 1105.8(b), respectively.

Treasury, Room 11000, 1750 Pennsylvania Avenue, NW., Washington, DC 20220.

Dates: Written comments should be received on or before April 16, 2007 to be assured of consideration.

Internal Revenue Service (IRS)

OMB Number: 1545–1865.
Type of Review: Extension.
Title: Notice 2003–75, Registered Retirement Savings Plans (RRSP) and Registered Income Funds (RRIF) Information Reporting.
Description: This notice announces an alternative, simplified reporting regime for the owners of certain Canadian Individual retirement plans that have been subject to reporting on Forms 3520 and 3520–A, and it describes the interim reporting rules that taxpayers must follow until a new form is available.
Respondents: Individuals or households.
Estimated Total Burden Hours: 1,500,000 hours.

OMB Number: 1545–1555.
Type of Review: Extension.
Title: REG–115795–97 (Final) General Rules for Making and Maintaining Qualified Electing Fund Elections.
Description: The regulations provide rules for making section 1295 elections and satisfying annual reporting requirements for such elections, revoking section 1295 elections, and making retroactive section 1295 elections.
Respondents: Businesses and other for-profit institutions.
Estimated Total Burden Hours: 623 hours.

OMB Number: 1545–1868.
Type of Review: Extension.
Title: REG–116664–01 (NPRM and Temporary) Guidance To Facilitate Business Electronic Filing.
Description: These regulations remove certain impediments to the electronic filing of business tax returns and other forms. The regulations reduce the number of instances in which taxpayers must attach supporting documents to their tax returns. The regulations also expand slightly the required content of a statement certain taxpayers must submit with their returns to justify deductions for charitable contributions.
Respondents: Businesses and other for-profit institutions.
Estimated Total Burden Hours: 250,000 hours.

OMB Number: 1545–0145.
Type of Review: Extension.
Title: Notice to Shareholder of Undistributed Long-Term Capital Gains.
Form: 2439.
Description: Form 2439 is sent by regulated investment companies and real estate investment trusts to report undistributed capital gains and the amount of tax paid on these gains designated under IRC section 852(b)(3)(D) or 857(b)(3)(D). The company, the trust, and the shareholder file copies of Form 2439 with IRS. IRS uses the information to check shareholder compliance.
Respondents: Businesses and other for-profit institutions.
Estimated Total Burden Hours: 29,995 hours.

OMB Number: 1545–1379.
Type of Review: Extension.
Title: Excise Taxes on Excess Inclusions of REMIC Residual Interests.
Form: 8831.
Description: Form 8831 is used by a real estate mortgage investment conduit (REMIC) to figure its excise tax liability under Code sections 860E(e)(1), 860E(e)(6), and 860E(e)(7). IRS uses the information to determine the correct tax liability of the REMIC.
Respondents: Businesses or other for-profit institutions.
Estimated Total Burden Hours: 237 hours.

OMB Number: 1545–0045.
Type of Review: Extension.
Title: Claim for Deficiency Dividends Deductions by a Personal Holding Company, Regulated Investment Company, or Real Estate Investment Trust.
Form: 976.
Description: Form 976 is filed by corporations that wish to claim a deficiency dividend deduction. The deduction allows the corporation to eliminate all or a portion of a tax deficiency. The IRS uses Form 976 to determine if shareholders have included amounts in gross income.
Respondents: Businesses and other for-profit institutions.
Estimated Total Burden Hours: 3,830 hours.

OMB Number: 1545–1813.
Type of Review: Extension.
Title: Health Coverage Tax Credit (HCTC) Advance Payments.
Form: 1099–H.
Description: Form 1099–H is used to report advance payments of health insurance premiums to qualified recipients for their use in computing the allowable health insurance credit on Form 8885.
Respondents: Businesses and other for-profit institutions.
Estimated Total Burden Hours: 33,000 hours.

OMB Number: 1545–0044.
Type of Review: Extension.
Title: Corporation Claim for Deduction for Consent Dividends.
Form: 973.
Description: Corporations file Form 973 to claim a deduction for dividends paid. If shareholders consent and IRS approves, the corporation may claim a deduction for dividends paid, which reduces the corporation's tax liability. IRS uses Form 973 to determine if shareholders have included the dividend in gross income.
Respondents: Businesses or other for-profit institutions.
Estimated Total Burden Hours: 2,210 hours.

OMB Number: 1545–0755.
Type of Review: Extension.
Title: LR–58–83 (Final) Related Group Election With Respect to Qualified Investments in Foreign Base Company Shipping Operations.
Description: The election described in the attached justification converted an annual election to an election effective until revoked. The computational information required is necessary to assure that the U.S. shareholder correctly reports any shipping income of its controlled foreign corporations which is taxable to that shareholder.
Respondents: Businesses or other for-profit institutions.
Estimated Total Burden Hours: 205 hours.

Clearance Officer: Glenn P. Kirkland, (202) 622–3428, Internal Revenue Service, Room 6516, 1111 Constitution Avenue, NW., Washington, DC 20224.

OMB Reviewer: Alexander T. Hunt, (202) 395–7316, Office of Management and Budget, Room 10235, New Executive Office Building, Washington, DC 20503.

Robert Dahl,
Treasury PRA Clearance Officer.
[FR Doc. E7–4781 Filed 3–14–07; 8:45 am]
BILLING CODE 4830–01–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

Proposed Collection; Comment Request for Form 990–N

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice and request for comments.

SUMMARY: The Department of the Treasury, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on proposed and/or continuing information

collections, as required by the Paperwork Reduction Act of 1995, Public Law 104–13 (44 U.S.C. 3506(c)(2)(A)). Currently, the IRS is soliciting comments concerning Form 990–N, Electronic Notice (e-Postcard) for Tax-Exempt Organizations Not Required To File Form 990 or 990–EZ.

DATES: Written comments should be received on or before May 14, 2007 to be assured of consideration.

ADDRESSES: Direct all written comments to Glenn Kirkland, Internal Revenue Service, Room 6516, 1111 Constitution Avenue, NW., Washington, DC 20224.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of the forms and instructions should be directed to Allan Hopkins, (202) 622–6665, or at Internal Revenue Service, Room 6516, 1111 Constitution Avenue, NW., Washington, DC 20224, or through the Internet, at *Allan.M.Hopkins@irs.gov.*

SUPPLEMENTARY INFORMATION: Title: Electronic Notice (e-Postcard) for Tax-Exempt Organizations Not Required To File Form 990 or 990–EZ.

OMB Number: 1545–XXXX.

Form Number: 990–N.

Abstract: Section 1223 of the Pension Protection Act of 2006 (PPA ’06), enacted on August 17, 2006, amended Internal Revenue Code (Code) section 6033 by adding Code section 6033(i), which requires certain tax-exempt organizations to file an annual electronic notice (Form 990–N) for tax years beginning after December 31, 2006. These organizations are not required to file Form 990 (or Form 990–EZ) because their gross receipts are normally $25,000 or less.

Current Actions: This is a new form.

Type of Review: New collection.

Affected Public: Not-for-profit institutions.

Estimated Number of Respondents: 520,000.

Estimated Time Per Respondent: 15 min.

Estimated Total Annual Burden Hours: 130,000.

The following paragraph applies to all of the collections of information covered by this notice:

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB control number. Books or records relating to a collection of information must be retained as long as their contents may become material in the administration of any internal revenue law. Generally, tax returns and tax return information are confidential, as required by 26 U.S.C. 6103.

Request for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record. Comments are invited on: (a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency’s estimate of the burden of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology; and (e) estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Approved: March 7, 2007.

Glenn Kirkland,

IRS Reports Clearance Officer.

[FR Doc. E7–4699 Filed 3–14–07; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

Proposed Collection; Comment Request for Notice 2006–109

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice and request for comments.

SUMMARY: The Department of the Treasury, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on proposed and/or continuing information collections, as required by the Paperwork Reduction Act of 1995, Public Law 104–13 (44 U.S.C. 3506(c)(2)(A)). Currently, the IRS is soliciting comments concerning Notice 2006–109, Interim Guidance Regarding Supporting Organizations and Donor Advised Funds.

DATES: Written comments should be received on or before May 14, 2007 to be assured of consideration.

ADDRESSES: Direct all written comments to Glenn P. Kirkland, Internal Revenue Service, Room 6516, 1111 Constitution Avenue, NW., Washington, DC 20224.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of notice should be directed to Allan Hopkins, at (202) 622–6665, or at Internal Revenue Service, room 6516, 1111 Constitution Avenue NW., Washington, DC 20224, or through the Internet, at Allan.M.Hopkins@irs.gov.

SUPPLEMENTARY INFORMATION: *Title:* Interim Guidance Regarding Supporting Organizations and Donor Advised Funds.

OMB Number: 1545–2050.

Notice Number: Notice 2006–109.

Abstract: This notice provides private foundation with options in collecting information to assist in determining whether grants to certain supporting organizations are qualifying distributions and are not taxable expenditures. Collecting such information will provide private foundations with relief from the new excise taxes imposed under amended sections 4942 and 4945 of the Code. It also provides relief from excise taxes imposed under new section 4966 of the Code. A sponsoring organization of certain donor advised funds will not be subject to the new taxes for distributions from employer-sponsored disaster relief funds or for distributions of certain educational grants if the organization collects and maintains the required documentation. The Notice clarifies that existing documentation requirements for employer-sponsored relief programs and educational grants apply to these funds.

Current Actions: There are no changes being made to the notice at this time. This is a new notice

Type of Review: Approval of new collection.

Affected Public: Not-for-profit institutions.

Estimated Number of Respondents: 65,000.

Estimated Average Time Per Respondent: 9 hours, 25 minutes.

Estimated Total Annual Burden Hours: 612,294.

The following paragraph applies to all of the collections of information covered by this notice:

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB control number. Books or records relating to a collection of information must be retained as long as their contents may become material in the administration of any internal revenue law. Generally, tax returns and tax return information are confidential, as required by 26 U.S.C. 6103.

Request for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All

comments will become a matter of public record. Comments are invited on: (a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology; and (e) estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Approved: March 8, 2007.

Glenn Kirkland,

IRS Reports Clearance Officer.

[FR Doc. E7–4700 Filed 3–14–07; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

Request for Nominations to the Electronic Tax Administration Advisory Committee (ETAAC)

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice.

SUMMARY: The Electronic Tax Administration Advisory Committee (ETAAC) was established to provide continued input into the development and implementation of the Internal Revenue Service (IRS) strategy for electronic tax administration. The ETAAC provides an organized public forum for discussion of electronic tax administration issues in support of the overriding goal that paperless filing should be the preferred and most convenient method of filing tax and information returns. ETAAC members convey the public's perception of IRS electronic tax administration activities, offer constructive observations about current or proposed policies, programs, and procedures, and suggest improvements. This document seeks nominations of individuals to be considered for selection as Committee members.

The Director, Electronic Tax Administration (ETA) will assure that the size and organizational representation of the ETAAC obtains balanced membership and includes representatives from various groups including: (1) Tax practitioners and preparers, (2) transmitters of electronic returns, (3) tax software developers, (4) large and small business, (5) employers and payroll service providers, (6) individual taxpayers, (7) financial industry (payers, payment options and best practices), (8) system integrators (technology providers), (9) academic (marketing, sales or technical perspectives), (10) trusts and estates, (11) tax exempt organizations, and (12) state and local governments. We are soliciting nominations from professional and public interest groups, IRS officials, the Department of Treasury, and Congress. Members serve a three-year term on the ETAAC to allow a change in membership. The change of members on the Committee ensures that different perspectives are represented. All travel expenses within government guidelines will be reimbursed. Potential candidates must pass an IRS tax compliance check and Federal Bureau of Investigation (FBI) background investigation.

DATES: Applications and/or written nominations must be received no later than Monday, April 30, 2007.

ADDRESSES: Completed applications and/or written nominations should be submitted by using one of the following methods:

- E-mail: Send to *etaac@irs.gov*
- Mail: Send to Internal Revenue Service, Electronic Tax Administration, SE:W:ETA:S:RM, 5000 Ellin Road (M/Stop C4–470, Attn: Cassandra Daniels (C4–226), Lanham, Maryland 20706.
- Fax: Send via facsimile to (202) 283–4829 (not a toll-free number).

Application packages can be obtained by sending an e-mail to *etaac@irs.gov* or calling (202) 283–2178 (not a toll-free number).

FOR FURTHER INFORMATION CONTACT: Cassandra Daniels, (202) 283–2178 or send an e-mail to *etaac@irs.gov.*

SUPPLEMENTARY INFORMATION: The ETAAC will provide continued input into the development and implementation of the Internal Revenue Service (IRS) strategy for electronic tax administration. The ETAAC members will convey the public's perception of IRS electronic tax administration activities, offer constructive observations about current or proposed policies, programs, and procedures, and suggest improvements. The ETAAC will also provide an annual report to Congress on IRS progress in meeting the Restructuring and Reform Act of 1998 goals for electronic filing of tax returns. This activity is based on the authority to administer the Internal Revenue laws conferred upon the Secretary of the Treasury by section 7802 of the Internal Revenue Code and delegated to the Commissioner of the Internal Revenue. The ETAAC will research, analyze, consider, and make recommendations on a wide range of electronic tax administration issues and will provide input into the development of the strategic plan for electronic tax administration.

Nominations should describe and document the proposed member's qualifications for membership to the Committee. Equal opportunity practices will be followed in all appointments to the Committee. To ensure that the recommendations of the Committee have taken into account the needs of the diverse groups served by the Department, membership will include, to the extent practicable, individuals, with demonstrated ability to represent minorities, women, and persons with disabilities. The Secretary of Treasury will review the recommended candidates and make final selections.

Dated: March 6, 2007.

Gregory Kay,

Director, Strategic Services Division.

[FR Doc. E7–4698 Filed 3–14–07; 8:45 am]

BILLING CODE 4830–01–P

Federal Register

Thursday,

March 15, 2007

Part II

Department of Energy

Federal Energy Regulatory Commission

18 CFR Parts 35 and 37

Preventing Undue Discrimination and Preference in Transmission Service; Final Rule

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Parts 35 and 37

[Docket Nos. RM05–17–000 and RM05–25–000; Order No. 890]

Preventing Undue Discrimination and Preference in Transmission Service

Issued February 16, 2007.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is amending the regulations and the *pro forma* open access transmission tariff adopted in Order Nos. 888 and 889 to ensure that transmission services are provided on a basis that is just, reasonable and not unduly discriminatory or preferential. The final rule is designed to: Strengthen the *pro forma* open-access transmission tariff, or OATT, to ensure that it achieves its original purpose of remedying undue discrimination; provide greater specificity to reduce opportunities for undue discrimination and facilitate the Commission's enforcement; and increase transparency in the rules applicable to planning and use of the transmission system.

EFFECTIVE DATE: This rule will become effective May 14, 2007.

FOR FURTHER INFORMATION CONTACT: Daniel Hedberg (Technical Information), Office of Energy Markets and Reliability, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–6243.

W. Mason Emnett (Legal Information), Office of the General Counsel—Energy Markets, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–6540.

Kathleen Barrón (Legal Information), Office of the General Counsel—Energy Markets, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–6461.

SUPPLEMENTARY INFORMATION:

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Before Commissioners: Joseph T. Kelliher, Chairman; Suedeen G. Kelly, Marc Spitzer, Philip D. Moeller, and Jon Wellinghoff.

I. Introduction

1. This Final Rule addresses and remedies opportunities for undue discrimination under the *pro forma* Open Access Transmission Tariff (OATT) adopted in 1996 by Order No. 888.[1] This landmark rulemaking fostered greater competition in wholesale power markets by reducing barriers to entry in the provision of transmission service. In the ten years since Order No. 888, however, the Commission has found that the OATT contains flaws that undermine realizing its core objective of remedying undue discrimination. In the Notice of Proposed Rulemaking (NOPR) issued on May 19, 2006, the Commission proposed to remedy those flaws.[2] After receiving approximately 6,500 pages of comments from close to 300 parties, we now take final action. We highlight below the most critical reforms being adopted today.

2. First, the Final Rule will increase nondiscriminatory access to the grid by eliminating the wide discretion that transmission providers currently have in calculating available transfer capability (ATC).[3] The calculation of ATC is one of the most critical functions under the OATT because it determines whether transmission customers can access alternative power supplies. Despite this, the existing OATT does not prescribe how ATC should be calculated because the Commission sought to rely on voluntary efforts by the industry to develop consistent methods of ATC calculation. This voluntary industry effort has not proven successful. The Commission therefore acts today to require public utilities, working through the North American Electric Reliability Corporation (NERC), to develop consistent methodologies for ATC calculation and to publish those methodologies to increase transparency. This important reform will eliminate the wide discretion that exists today in calculating ATC and ensure that customers are treated fairly in seeking alternative power supplies.

3. Second, the Final Rule will increase the ability of customers to access new generating resources and promote efficient utilization of transmission by requiring an open, transparent, and coordinated transmission planning process. Transmission planning is a critical function under the *pro forma* OATT because it is the means by which customers consider and access new sources of energy and have an opportunity to explore the feasibility of non-transmission alternatives. Despite this, the existing *pro forma* OATT provides limited guidance regarding how transmission customers are treated in the planning process and provides them very little information on how transmission plans are developed. These deficiencies are serious, given the substantial need for new infrastructure in this Nation.[4] We act today to remedy these deficiencies by requiring transmission providers to open their transmission planning process to customers, coordinate with customers regarding future system plans, and share necessary planning information with customers.

4. Third, the Final Rule will also increase the efficient utilization of

[1] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. § 31,036 (1996), *order on reh'g,* Order No. 888–A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. § 31,048 (1997), *order on reh'g,* Order No. 888–B, 81 FERC § 61,248 (1997), *order on reh'g,* Order No. 888–C, 82 FERC § 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group* v. *FERC,* 225 F.3d 667 (D.C. Cir. 2000) (*TAPS* v. *FERC*), *aff'd sub nom. New York* v. *FERC,* 535 U.S. 1 (2002).

[2] *Preventing Undue Discrimination and Preference in Transmission Service,* Notice of Proposed Rulemaking, 71 FR 32,636 (Jun. 6, 2006), FERC Stats. & Regs. § 32,603 (2006).

[3] The Commission used the term ''Available Transmission Capability'' in Order No. 888 to describe the amount of additional capability available in the transmission network to accommodate additional requests for transmission services. To be consistent with the term generally accepted throughout the industry, the Commission revises the *pro forma* OATT to adopt the term ''Available Transfer Capability.''

[4] Congress placed special emphasis on the development of transmission infrastructure, including the consideration of advanced transmission technologies, in the Energy Policy Act of 2005 (EPAct 2005). *See* Pub. L. 109–58, 119 Stat. 594 (to be codified in scattered titles of the U.S.C.). The Commission has taken steps to implement that goal in numerous contexts, including recent rulemaking proceedings that address the promotion of transmission investment through pricing reform and the siting of certain transmission facilities. *See Promoting Transmission Investment through Pricing Reform,* Order No. 679, 71 FR 43294 (Jul. 31, 2006), FERC Stats. & Regs. § 31,222 (2006), *order on reh'g,* Order No. 679–A, 72 FR 1152 (Jan. 10, 2007), FERC Stats. & Regs. § 31,236 (2007), *reh'g pending; Regulations for Filing Applications for Permits to Site Interstate Electric Transmission Facilities,* Order No. 689, 71 FR 69440 (Dec. 1, 2006), FERC Stats. & Regs. § 31,234 (2006), *reh'g pending.* As discussed herein, several actions taken in this Final Rule also relate to the need for investments in transmission infrastructure and are consistent with the Commission's responsibilities under EPAct 2005.

transmission by eliminating artificial barriers to use of the grid. The existing *pro forma* OATT allows a transmission provider to deny a request for long-term point-to-point service if the request cannot be satisfied in only one hour of the requested term. This practice discourages the efficient use of the existing grid and precludes access to alternative power supplies. We reform this practice by requiring that a conditional firm option be offered to customers seeking long-term point-to-point service, *i.e.*, conditional firm service. We also modify the redispatch obligations of transmission providers to increase the efficient utilization of the grid, while also ensuring that reliability to native load customers is maintained.

5. Fourth, by adopting these and other reforms, the Final Rule facilitates the use of clean energy resources such as wind power. Conditional firm service is particularly important to wind resources that can provide significant economic and environmental value even if curtailed under limited circumstances. Open and coordinated transmission planning will enhance the ability of customers to access clean energy resources as part of their future resource portfolio. The Final Rule also benefits clean energy resources by reforming energy and generator imbalance charges. These reforms are particularly important to intermittent resources such as wind power because these resources have limited ability to control their output and, hence, must be assured that imbalance charges are no more than required to provide appropriate incentives for prudent behavior.

6. Fifth, the Final Rule will strengthen compliance and enforcement efforts. We are increasing the transparency of *pro forma* OATT administration, thereby increasing the ability of customers and our Office of Enforcement to detect undue discrimination. We are adopting operational penalties for clear violations of an OATT, thereby enhancing compliance while also reducing the burdens on our Office of Enforcement. We are also increasing the clarity of many other OATT requirements, thereby facilitating compliance by transmission providers with our regulations. This Final Rule thus reflects the close integration of our Office of Enforcement into policy development at the Commission. Several of the reforms we adopt today are informed by our experience with OATT administration through oversight, audits, and investigations performed by the Office of Enforcement.

7. Finally, we modify and improve several provisions of the *pro forma* OATT using our experience over the past ten years and clarify others that have proven ambiguous. For example, we reform our rollover rights policy to ensure that the rights and obligations of rollover customers are consistent with the resulting obligations of transmission providers to plan and upgrade the system to accommodate rollovers. We remove the price cap on reassigned capacity because it is not necessary to remedy market power and doing so will otherwise increase the efficient use of existing capacity. We increase the efficient use of existing capacity by providing a priority to certain ''pre-confirmed'' requests for service. We increase certainty by providing greater clarity regarding the wholesale contracts that qualify as network resources. We also adopt numerous clarifications that should assist transmission providers and customers in implementing and using the *pro forma* OATT

8. Our actions in this proceeding have been informed to a great extent by the comments received in response to our notices of inquiry in the above-captioned dockets and the subsequent NOPR.[5] We appreciate the time and thoughtfulness of all sectors of the industry in preparing comments. We have found them very informative and useful in reaching our decisions in this Final Rule.

II. Background

A. Historical Antecedent

9. In the NOPR, the Commission explained the historical background that led up to the issuance of Order No. 888, and the initiation of this rulemaking proceeding. We repeat that history here to place in context the actions we take today.

10. In the first few decades after enactment of the Federal Power Act (FPA) in 1935, the industry was characterized mostly by self-sufficient, vertically integrated electric utilities, in which generation, transmission, and distribution facilities were owned by a single entity and sold as part of a bundled service to wholesale and retail customers. Most electric utilities built their own power plants and transmission systems, entered into interconnection and coordination arrangements with neighboring utilities, and entered into long-term contracts to make wholesale requirements sales (bundled sales of generation and transmission) to municipal, cooperative, and investor-owned utilities connected to each utility's transmission system. Each system covered a limited service area, which was defined by the retail franchise decisions of State regulatory agencies. This structure of separate systems arose naturally primarily due to cost and the technological limitations on the distance over which electricity could be transmitted.

11. A number of statutory, economic, and technological developments in the 1970s led to an increase in coordinated operations and competition. Among those was the passage of the Public Utility Regulatory Policies Act of 1978 (PURPA),[6] which was designed to lessen dependence on foreign fossil fuels by encouraging the development of alternative generation sources and imposing a mandatory purchase obligation on utilities for generation from such sources. PURPA also enabled the Commission to order wheeling of electricity under limited circumstances.[7] The rapid expansion and performance of the independent power industry following the enactment of PURPA demonstrated that traditional, vertically integrated public utilities need not be the only sources of reliable power. During this period, the profile of generation investment began to change, and a market for non-traditional power supply beyond the purchases required by PURPA began to emerge. The economic and technological changes in the transmission and generation sectors helped encourage many new entrants in the generating markets that could sell electric energy profitably with smaller scale technology at a lower price than many utilities selling from their existing generation facilities at rates reflecting cost. However, it became increasingly clear that the potential consumer benefits that could be derived from these technological advances could be realized only if more efficient generating plants could obtain access to the regional transmission grids. Because many traditional vertically integrated utilities still did not provide open access to third parties and favored their own generation if and when they

[5] *Preventing Undue Discrimination and Preference in Transmission Services,* Notice of Inquiry, 112 FERC ¶ 61,299 (2005) (NOI); *Information Requirements for Available Transfer Capability,* Notice of Inquiry, 111 FERC ¶ 61,274 (2005) (ATC NOI).

[6] Pub. L. 95–617, 92 Stat. 3117 (1978) (codified in U.S.C. titles 15, 16, 26, 30, 42, and 43).

[7] Section 211 of the FPA, 16 U.S.C. 824j. In earlier years, a few customers were able to obtain access as a result of litigation, beginning with the U.S. Supreme Court's decision in *Otter Tail Power Company* v. *United States,* 410 U.S. 366 (1973). Additionally, some customers gained access by virtue of Nuclear Regulatory Commission license conditions and voluntary preference power transmission arrangements associated with Federal power marketing agencies. *See, e.g., Consumers Power Co.,* 6 NRC 887, 1036–44 (1977); *Toledo Edison Co.,* 10 NRC 265, 327–34 (1979); *Florida Municipal Power Agency* v. *Florida Power and Light Co.,* 839 F. Supp. 1563 (M.D. Fla. 1993).

provided transmission access to third parties, access to cheaper, more efficient generation sources remained limited.

12. The Commission encouraged the development of independent power producers (IPPs), as well as emerging power marketers, by authorizing market-based rates for their power sales on a case-by-case basis, and by encouraging more widely available transmission access on a case-by-case basis. Market-based rates helped to develop competitive bulk power markets by allowing generating utilities to move more quickly and flexibly to take advantage of short-term or even long-term market opportunities than those utilities operating under traditional cost-of-service tariffs. In approving these market-based rates, the Commission required that the seller and its affiliates lack market power or mitigate any market power that they may have had.[8] The major concern of the Commission was whether the seller or its affiliates could limit competition and thereby drive up prices. A key inquiry became whether the seller or its affiliates owned or controlled transmission facilities in the relevant service area and therefore, by denying access or imposing discriminatory terms or conditions on transmission service, could foreclose other generators from competing. Beginning in the late 1980s, in order to mitigate their market power to meet the Commission's conditions, public utilities seeking Commission authorization for blanket approval of market-based rates for generation services under section 205 of the FPA filed ''open access'' transmission tariffs of general applicability.[9] The Commission also approved proposed mergers under section 203 of the FPA on the condition that the merging companies remedy anticompetitive effects potentially caused by the merger by filing ''open access'' tariffs. The early tariffs submitted in market-based rate proceedings under section 205 and merger proceedings under section 203 did not, however, provide access to the transmission system that was comparable to the service the transmission providers used for their own purposes. Rather, they typically made available only point-to-point transmission service, *i.e.*, service from a single point of receipt to a single point of delivery. As these early tariffs were offered only by transmission providers that volunteered to provide service to third parties, they resulted in a patchwork of open access that was not sufficient to facilitate wholesale generation markets.

13. In response to the competitive developments following PURPA, and the fact that limited transmission access and significant regulatory barriers continued to constrain the development of generation by independent power producers, Congress enacted Title VII of the Energy Policy Act of 1992 (EPAct 1992).[10] EPAct 1992 reduced regulatory barriers to entry by creating a class of ''Exempt Wholesale Generators'' that were exempt from the requirements of the Public Utility Holding Company Act of 1935.[11] EPAct 1992 also expanded the Commission's authority to approve applications for transmission services under sections 211 and 212 of the FPA.[12] Though the Commission aggressively implemented expanded section 211, it ultimately concluded that the procedural limitations in section 211 thwarted the Commission's ability to effectively eliminate undue discrimination in the provision of transmission service.

B. Order No. 888 and Subsequent Reforms

14. In April 1996, as part of its statutory obligation under sections 205 and 206 of the FPA to remedy undue discrimination, the Commission adopted Order No. 888 prohibiting public utilities from using their monopoly power over transmission to unduly discriminate against others. In that order, the Commission required all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to file open access non-discriminatory transmission tariffs that contained minimum terms and conditions of non-discriminatory service. It also obligated such public utilities to ''functionally unbundle'' their generation and transmission services. This meant public utilities had to take transmission service (including ancillary services) for their own new wholesale sales and purchases of electric energy under the open access tariffs, and to separately state their rates for wholesale generation, transmission and ancillary services.[13] Each public utility was required to file the *pro forma* OATT included in Order No. 888 without any deviation (except a limited number of terms and conditions that reflect regional practices).[14] After the effectiveness of their OATTs, public utilities were allowed to file, pursuant to section 205 of the FPA, deviations that were consistent with or superior to the *pro forma* OATT's terms and conditions. Because certain owners, controllers or operators of interstate transmission facilities were not subject to the Commission's jurisdiction under sections 205 and 206 and thus were not subject to Order No. 888, the Commission adopted a reciprocity provision in the *pro forma* OATT that conditions the use by a non-public utility of a public utility's open access services on an agreement to offer non-discriminatory transmission services in return.

15. In addition to imposing the functional unbundling requirement, the Commission also encouraged broader reforms through the formation of independent system operators (ISOs). The Commission stated that ISOs can provide significant benefits such as enhancing regional efficiencies and further remedying undue discrimination.[15] While the Commission declined to mandate ISOs, it set forth eleven principles for assessing ISO proposals submitted to the Commission.[16]

16. Order No. 888 also clarified the Commission's interpretation of the Federal and State jurisdictional boundaries over transmission and local distribution. While Order No. 888 reaffirmed that the Commission has exclusive jurisdiction over the rates,

[8] *See, e.g., Dartmouth Power Associates Limited Partnership,* 53 FERC ¶ 61,117 (1990); *Commonwealth Atlantic Limited Partnership,* 51 FERC ¶ 61,368 (1990); *Doswell Limited Partnership,* 50 FERC ¶ 61,251 (1990); *Citizens Power & Light Co.,* 48 FERC ¶ 61,210 (1989); *Ocean State Power,* 44 FERC ¶ 61,261 (1988); and *Orange and Rockland Utilities, Inc.,* 42 FERC ¶ 61,012 (1988).

[9] *See* Order No. 888 at 31,644 n.52.

[10] Pub. L. 102–486, 106 Stat. 2776 (1992) (codified at, among other places, 15 U.S.C. 79z–5a and 16 U.S.C. 796 (22–25), 824j–l).

[11] 15 U.S.C. 79a, *repealed by* EPAct 2005 sec. 1263; *see Repeal of the Public Utility Holding Company Act of 1935 and Enactment of the Public Utility Holding Company Act of 2005,* Order No. 667, 70 FR 75592 (Dec. 20, 2005), FERC Stats. & Regs. ¶ 31,197 (2005), *order on reh'g,* Order No. 667–A, 71 FR 28446 (May 16, 2006), FERC Stats. & Regs. ¶ 31,213 (2006), *order on reh'g,* Order No. 667–B, 71 FERC 42750 (Jul. 28, 2006), FERC Stats. & Regs. ¶ 31,224 (2006), *reh'g pending.*

[12] 16 U.S.C. 824j (authorizing the Commission to require transmission utilities to provide service in certain circumstances); 16 U.S.C. 824k (establishing rates for service provided pursuant to an order under section 211).

[13] This is known as ''functional unbundling'' because the transmission element of a wholesale sale is separated or unbundled from the generation element of that sale, although the public utility may provide both functions. *See infra* section IV.B.4 of this Final Rule.

[14] *See* Order No. 888 at 31,769–70 (noting that the *pro forma* OATT expressly identified certain non-rate terms and conditions, such as the time deadlines for determining available transfer capability in section 18.4 or scheduling changes in sections 13.8 and 14.6, that may be modified to account for regional practices if such practices are reasonable, generally accepted in the region, and consistently adhered to by the transmission provider).

[15] Order No. 888 at 31,655.

[16] *Id.* at 31,730–32.

terms, and conditions of unbundled retail transmission in interstate commerce by public utilities, it nevertheless recognized the legitimate concerns of State regulatory authorities regarding the transmission component of bundled retail sales. The Commission therefore declined to extend its unbundling requirement to the transmission component of bundled retail sales. On appeal, the U.S. Supreme Court affirmed this element of Order No. 888, finding that the Commission made a statutorily permissible choice.[17]

17. The same day it issued Order No. 888, the Commission issued a companion order, Order No. 889,[18] addressing the separation of vertically integrated utilities' transmission and merchant functions, the information transmission providers were required to make public, and the electronic means they were required to use to do so. Order No. 889 imposed Standards of Conduct governing the separation of, and communications between, the utility's transmission and wholesale power functions, to prevent the utility from giving its merchant arm preferential access to transmission information. All public utilities that owned, controlled or operated facilities used in the transmission of electric energy in interstate commerce were required to create or participate in an Open Access Same-Time Information System (OASIS) that was to provide existing and potential transmission customers the same access to transmission information.

18. Among the information public utilities were required to post on their OASIS was the transmission provider's calculation of ATC. Though the Commission acknowledged that before-the-fact measurement of the availability of transmission service is ''difficult,'' it concluded that it was important to give potential transmission customers ''an easy-to-understand indicator of service availability.'' [19] Because formal methods did not then exist to calculate ATC and total transfer capability (TTC), the Commission encouraged industry efforts to develop consistent methods for calculating ATC and TTC.[20] Order No. 889 ultimately required transmission providers to base their calculations on ''current industry practices, standards and criteria'' and to describe their methodology in their tariffs.[21] The Commission noted that the requirement that transmission providers purchase only ATC that is posted as available ''should create an adequate incentive for them to calculate ATC and TTC as accurately and as uniformly as possible.'' [22]

19. The electric industry continued to undergo economic and regulatory changes in the years following the issuance of Order No. 888. Retail access was adopted by approximately 25 states in the late 1990s.[23] This State restructuring activity spurred significant changes at the wholesale level as well by encouraging or requiring the divestiture of generation plants by traditional electric utilities and the development of ISOs that could manage short-term energy markets necessary to support retail access. At the same time, there was a significant increase in the number of mergers between traditional electric utilities and between electric utilities and gas pipeline companies, and large increases in the number of power marketers and independent generation facility developers entering the marketplace. Trade in bulk power markets increased significantly and the Nation's transmission grid was used more heavily and in new ways as customers took advantage of the *pro forma* OATT and purchased power from competitive sellers.

20. In the wake of these changes, in December 1999, the Commission adopted Order No. 2000.[24] That rulemaking recognized that Order No. 888 set the foundation upon which competitive electric markets could develop, but did not eliminate the potential to engage in undue discrimination and preference in the provision of transmission service.[25] The rulemaking also recognized that Order No. 888 did not address the regional nature of the grid, including the treatment of parallel flows, pancaked rates, and congestion management. Thus, the Commission encouraged the creation of RTOs to address important operational and reliability issues and eliminate any residual discrimination in transmission services that can occur when the operation of the transmission system remains in the control of a vertically integrated utility. The Commission found that RTOs would increase the efficiency of wholesale markets by eliminating pancaked rates, internalizing parallel flow, managing congestion efficiently, and operating markets for energy, capacity and ancillary services. The Commission established an open, collaborative process that relied on voluntary regional participation to design RTOs tailored to the specific needs of each region. The Commission noted, however, that ''[i]f the industry fails to form RTOs under this approach, the Commission will reconsider what further regulatory steps are in the public interest.''[26]

21. Following Order No. 2000, RTOs were approved in several regions of the country including the Northeast (PJM; ISO New England),[27] the Midwest (MISO) and the South (SPP). In most cases, RTOs have assumed responsibility for calculating ATC across the footprint of the RTO, as well as the planning and expansion of the transmission grid, at least for facilities necessary for maintaining system reliability. However, large areas of the Nation have not developed RTOs using the voluntary structure adopted by the Commission in Order No. 2000. Moreover, transmission customers have complained that even in RTO markets there are instances when comparable transmission service is not provided, particularly in the area of transmission planning.

C. EPAct 2005 and Recent Developments

22. Enacted on August 8, 2005, EPAct added a number of new authorities and priorities for the Commission and emphasized certain of its existing obligations. Among other things, EPAct 2005 recognized the importance of adequate transmission infrastructure development and its role in facilitating the development of competitive wholesale markets. The Congressional directives in EPAct 2005 are intended to reverse the decline in transmission infrastructure investment. For example, Congress required the Commission to adopt a rule establishing incentive ratemaking for transmission infrastructure to help promote reliability and reduce congestion.[28] Congress also

[17] *New York* v. *FERC,* 535 U.S. 1 (2002).

[18] *Open Access Same-Time Information System (Formerly Real-Time Information Networks) and Standards of Conduct,* Order No. 889, 61 FR 21737 (May 10, 1996), FERC Stats. & Regs. ¶ 31,035 (1996), *order on reh'g,* Order No. 889–A, FERC Stats. & Regs. ¶ 31,049 (1997), *order on reh'g,* Order No. 889–B, 81 FERC ¶ 61,253 (1997).

[19] Order No. 889 at 31,605.

[20] *Id.* at 31,607.

[21] *Id.*

[22] *Id.*

[23] *See* Energy Information Administration, Retail Unbundling—U.S. Summary (2005), *http://www.eia.doe.gov/oil_gas/natural_gas/restructure/state/us.html.*

[24] *Regional Transmission Organizations,* Order No. 2000, 65 FR 809 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g,* Order No. 2000–A, 65 FR 12088 (Mar. 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Public Utility District No. 1 of Snohomish County, Washington* v. *FERC,* 272 F.3d 607 (D.C. Cir. 2001).

[25] Order No. 2000 at 31,015.

[26] *Id.* at 30,993.

[27] A list of commenter acronyms can be found in Appendix B.

[28] EPAct 2005 sec. 1241 (to be codified at section 219 of the FPA, 16 U.S.C. 824s).

directed the Commission to encourage the deployment of advanced technologies.[29] Congress further directed the Commission to ''exercise its authority'' under EPAct 2005 ''in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities.''[30] Congress also gave the Commission certain ''backstop'' transmission siting authority, and authorized the creation of interstate compacts establishing transmission siting agencies.[31] EPAct 2005 also authorized the Commission to require unregulated transmitting utilities (except for certain small entities) to provide access to their transmission facilities on a comparable basis.[32] Congress further ordered the Department of Energy (DOE) to study the benefits of economic dispatch and required the Commission to convene regional joint boards to develop a report to Congress containing recommendations for the use of security constrained economic dispatch within each region.[33] Congress also directed the Commission to facilitate price transparency in markets for the sale and transmission of electric energy in interstate commerce, having due regard for the public interest, the integrity of those markets, fair competition, and the protection of consumers, and it authorized the Commission to prescribe rules to provide for the dissemination of information about the availability and price of wholesale electric energy and transmission service.[34] Finally, Congress emphasized compliance with the Commission's regulations, adopting and increasing the civil and criminal penalties for violations of Commission-administered statutes and regulations.[35]

23. Recognizing the need for reform of Order No. 888 in light of the Commission's continuing concern regarding whether the *pro forma* OATT adequately remedies undue discrimination, the Commission issued an NOI on September 16, 2005[36] seeking comments on appropriate reforms of the Order No. 888 *pro forma* OATT. In the NOI, the Commission expressed its preliminary view that reforms to the *pro forma* OATT and public utilities' OATTs are necessary to avoid undue discrimination or preference in the provision of transmission service. The NOI sought comments on how best to accomplish the Commission's goals, specifically with respect to enhancements that are needed to (1) Remedy any unduly discriminatory or preferential application of the *pro forma* OATT or (2) improve the clarity of the Order No. 888 *pro forma* OATT and the individual public utility tariffs in order to more readily identify violations and facilitate compliance.

24. The Commission received over 4,000 pages of initial and reply comments on the NOI. Based on these comments, the comments submitted in response to the ATC NOI,[37] our experience in implementing Order No. 888, and the changes in the industry since we adopted it, the Commission proposed to reform the *pro forma* OATT in a number of ways. The Commission issued the NOPR on May 19, 2006 proposing a number of reforms aimed at remedying undue discrimination in the provision of open access transmission service and improving the clarity of the *pro forma* OATT and the individual tariffs of transmission providers in order to more readily identify violations and facilitate compliance. The Commission received over 5,700 pages of initial and reply comments in response. In response to comments on the particular issue of redispatch and conditional firm service (discussed in more detail below), the Commission issued a Notice of Request for Supplemental Comments on November 15, 2006,[38] that resulted in receipt of an additional 750 pages of comments.

25. Based on this voluminous record, the Commission concludes that reform of the *pro forma* OATT and associated amendments to its regulations are necessary to reduce the potential for undue discrimination and provide clarity in the obligations of transmission providers and customers alike. We turn next to a more complete explanation of this need for reform.

III. Need for Reform of Order No. 888

A. Opportunities for Undue Discrimination Continue To Exist

26. Although Order No. 888 has been successful in many important respects, the need for reform of the Order No. 888 *pro forma* OATT has been apparent for some time. In 1999, the Commission held, in adopting Order No. 2000, that the *pro forma* OATT could not fully remedy undue discrimination because transmission providers retained both the incentive and the ability to discriminate against third parties, particularly in areas where the *pro forma* OATT left the transmission provider with significant discretion.[39] The Commission made a similar finding in Order No. 2003,[40] holding that opportunities for undue discrimination continue to exist in areas where the *pro forma* OATT leaves transmission providers with substantial discretion.[41] The NOPR reaffirmed these findings, preliminarily concluding that opportunities for undue discrimination continue to exist in the provision of open access transmission service. The Commission therefore proposed a number of reforms to the *pro forma* OATT to address the opportunities and incentives transmission providers have to unduly discriminate.

Comments

27. Many commenters agree with the Commission that reforms to the *pro forma* OATT are needed because there continue to be both the opportunity and incentive for transmission providers to engage in undue discrimination.[42]

28. Several commenters offered examples of their experiences with transmission providers, where they believe transmission providers have acted in an unduly discriminatory

[29] EPAct 2005 sec. 1223 (to be codified at 42 U.S.C. 16422). Indeed, Congress provided specific guidance as to the types of advanced technologies that should be encouraged in infrastructure improvements to include, among others, optimized transmission line configurations (including multiple phased transmission lines), controllable load, distributed generation (including PV, fuel cells, and microturbines), and enhanced power device monitoring. *Id.*

[30] EPAct 2005 sec. 1233(a) (to be codified at section 217(b)(4) of the FPA, 16 U.S.C. 824q).

[31] EPAct 2005 sec. 1221(a) (to be codified at section 216 of the FPA, 16 U.S.C. 824p).

[32] EPAct 2005 sec. 1231 (to be codified at section 211A of the FPA, 16 U.S.C. 824j–1)

[33] EPAct 2005 sec. 1234 (to be codified at 42 U.S.C. 16432); EPAct 2005 sec. 1298 (to be codified at section 223 of the FPA, 16 U.S.C. 824w). EPAct 2005 sec. 1234(b) defined economic dispatch as ''the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities.''

[34] EPAct 2005 sec. 1281 (to be codified at section 220 of the FPA, 16 U.S.C. 824t).

[35] EPAct 2005 sec. 1284(d) (to be codified at section 316 of the FPA, 16 U.S.C. 825o); EPAct 2005 sec. 1284(e) (to be codified at section 316A of the FPA, 16 U.S.C. 825o–1).

[36] *See supra* note 5.

[37] *Id.*

[38] *Preventing Undue Discrimination and Preference in Transmission Service*, 117 FERC ¶ 61,185 (2006).

[39] Order No. 2000 at 31,105.

[40] *See Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 68 FR 49845 (Aug. 19, 2003), FERC Stats. & Regs. ¶ 31,146 at P 11–12 (2003), *order on reh'g*, Order No. 2003–A, 69 FR 15932 (Mar. 26, 2004), FERC Stats. & Regs. ¶ 31,160 (2004), *order on reh'g*, Order No. 2003–B, 70 FR 265 (Jan. 4, 2005), FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003–C, 70 FR 37,661 (Jun. 30, 2005), FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. National Association of Regulatory Utility Commissioners* v. *FERC*, No. 04–1148, 2007 U.S. App. LEXIS 626 (D.C. Cir. Jan. 12, 2007).

[41] Order No. 2003 at P 11–12.

[42] *E.g.*, APPA, EPSA, East Texas Cooperatives, Fayetteville, NRG, Occidental, TAPS, TDU Systems, Williams, Entegra Reply, and NRECA Reply.

fashion.[43] Constellation claims that on multiple occasions it has been denied a transmission request when the transmission provider's OASIS indicates that ATC is available, but Constellation had no effective and timely way to challenge that determination because of the ATC ''black box.'' Constellation states that given that its needs for transmission service are often near-term or immediate—*e.g.*, to facilitate a load-serving obligation or wholesale transaction that must be consummated quickly—seeking redress at the Commission for improperly denied service generally is not time- or cost-effective. Instead, Constellation asserts, it is often forced to accept the determination of the transmission provider that ATC is not available (even though its OASIS may indicate otherwise) and seek alternate transmission paths and/or products to consummate its transaction.

29. Powerex also describes instances where a transmission provider has granted short-term firm point-to-point transmission service requests to transmission customers who have been allowed to remain in the queue, even when zero ATC is posted, in the hopes that a transmission provider's OASIS site wrongly indicates zero ATC or will soon be updated. Powerex asserts that such practices clog the short-term point-to-point transmission queue with multiple requests and result in duplicative requests for service that reflect customers' attempts to secure service, rather than the actual quantity of service needed. Moreover, Powerex argues, transmission provider discretion in this area and the lack of transparency raise customer concerns about preferential treatment.

30. Occidental claims that it has first-hand experience with a vertically integrated transmission provider that, despite having an OATT, appears to have persistently used its transmission system to preferentially benefit its merchant function. Similarly, Williams alleges that its interests have been consistently and significantly compromised by the discretion afforded transmission providers in the interpretation of the OATT and the lack of transparency in requesting, scheduling and interrupting of transmission service.

31. Other commenters, however, argue that the Commission's proposed reforms are based on unsupported allegations of undue discrimination. EEI maintains that any opportunities to engage in undue discrimination have been largely mitigated by current regulatory policies and changes in the industry. EEI explains that, unlike the situation that existed when the Commission enacted Order No. 888, much of the country's transmission facilities are now under the control of RTOs and ISOs. In addition, EEI states, other transmission providers have transferred (or are in the process of transferring) the administration of their OATTs and OASIS functions to independent transmission service coordinators. Even among the transmission providers who have taken neither of those steps, EEI argues that the open access requirements of Order No. 888 and the Standards of Conduct of Order Nos. 889 and 2004 have largely eliminated the ability of transmission providers to engage in undue discrimination in the provision of transmission service.[44] In addition, EEI states, the Commission's expanded civil penalty authority added to the FPA by EPAct 2005 gives the Commission a powerful tool that will further eliminate any remaining incentive of transmission providers to engage in undue discrimination in the provision of transmission service. Therefore, EEI asserts, any modifications to the OATT should be narrowly tailored to address the *perceptions* of residual undue discrimination. To the extent that such perceptions exist, however, Community Power Alliance states that, in the absence of concrete record evidence, they are just that—perceptions.

32. Although Duke strongly supports, as a policy matter, OATT reforms that will eliminate the perception that undue discrimination is possible and/or likely, Duke argues that the FPA does not provide the Commission the authority to remedy mere ''opportunities'' to discriminate. Duke states that, in some cases, the Commission is attempting to remedy an opportunity for undue discrimination that does not exist or is proposing to impose a remedy that does not actually remedy the perceived opportunity. Duke notes, however, that some OATT terms and conditions are subject to multiple interpretations and argues that the Commission can, and should, justify the OATT reforms proposed in the NOPR as reforms needed to provide clarity to existing policies.

33. With regard to specific allegations made by commenters, several transmission providers respond that the examples given by transmission customers do not illustrate instances of undue discrimination. Rather, they assert, these examples demonstrate the transmission customers' lack of understanding of the OATT requirements, and the data available on OASIS.[45]

34. New Mexico Attorney General argues that the traditional State-regulated, vertically-integrated cost-of-service world is not in need of reform. Contrary to the ''conspiracy theorists'' who argue that utilities have an incentive to engage in undue discrimination and preference in transmission services, New Mexico Attorney General asserts that utilities have an incentive to maximize throughput and revenue between State-level rate cases because incremental transmission revenue is not deducted from the State-jurisdictional retail revenues between rate cases. Similarly, Southern, in its reply comments, asserts that broad claims of undue discrimination fail to take into consideration that vertically-integrated utilities have more of an incentive to act appropriately than do independent utilities because the former have more to lose (*e.g.*, loss of market-based rates, state prudence reviews of costs, *etc.*) if they are found to have engaged in wrong-doing. Southern states that any OATT revisions ultimately adopted by the Commission must be reasonably tailored to address an identified problem or to provide a specific improvement.

35. Other commenters argue that the Commission's focus should be on transmission providers in non-organized markets, arguing that remaining concerns about undue discrimination have already been addressed in the world of ISOs and RTOs.[46] According to ISO/RTO Council, this proceeding provides an opportunity for the Commission to harmonize the worlds of organized and non-organized markets in a manner that encourages competition, promotes non-discriminatory access, and maximizes the flow of electricity across various ISO/RTO and non-ISO/RTO regions. ISO/RTO Council states that, in the existing regulatory environment, a utility that is not a member of an ISO or RTO can sell into, or purchase from, an ISO or RTO market even though the non-ISO/RTO utility operates under tariff rules that are less open and transparent, particularly in terms of access to generation resources and pricing/system information, than their competitors that belong to an ISO or RTO. Such asymmetry, ISO/RTO Council argues, operates as an

[43] *See, e.g.*, Dow, Fayetteville, Occidental, and Williams.

[44] *See also* Southern Reply.

[45] *See, e.g.*, Entergy Reply, Progress Energy Reply, and Southern Reply.

[46] *E.g.*, Indicated New York Transmission Owners, ISO/RTO Council, and Northeast Utilities.

impediment to fair and non-discriminatory transmission access and management of grid congestion.

36. ISO/RTO Council states that its members do not seek to impose their market designs on the rest of the nation. At the same time, ISO/RTO Council argues that meaningful reform should ensure a level of transparency (of both price and the dispatch utilized by non-ISO/RTO vertically-integrated entities) in regions without an ISO or RTO that can assist the flow of electricity and enhance reliability and planning in both ISO/RTO and non-ISO/RTO regions.

37. Exelon urges the Commission to hold the transmission providers outside ISOs or RTOs to the same standard of non-discrimination that exists within those organizations. Further, MISO/PJM States argue that in order to achieve some level of independence in non-RTO regions, non-independent transmission providers should be encouraged to turn over operational control of their transmission systems to an independent coordinator of transmission whose functions would include security coordination, determination of ATC, granting of transmission service and oversight for transmission planning.

38. Finally, EPSA suggests that the Commission establish a one-year review period for the reformed *pro forma* OATT. EPSA urges the Commission to revisit this Final Rule after one year of operation under the reformed *pro forma* OATT to ensure that the revisions adopted here do, in fact, protect against non-discriminatory or preferential behavior by transmission providers. NRECA responds that, after this comprehensive rulemaking process, there is simply no need for another major look at the OATT in one year. Moreover, NRECA states, one year is likely too short a period for the Commission and industry participants to fully appreciate all of the consequences of those elements of OATT reform resulting from this proceeding. At the same time, NRECA agrees that the Commission should carefully monitor implementation of the reformed OATT. This monitoring, NRECA states, must be an ongoing process and cannot wait a year to begin.

Commission Determination

39. The Commission concludes that reforms are needed to address deficiencies in the *pro forma* OATT that have become apparent since 1996, by limiting remaining opportunities for undue discrimination. As the Commission found in Order No. 888, it is in the economic self-interest of transmission monopolists, particularly those with high-cost generation assets, to deny transmission or to offer transmission on a basis that is inferior to that which they provide to themselves.[47] Such an incentive can lead to unduly discriminatory behavior against third parties, particularly if public utilities have unnecessarily broad discretion in the application of their tariffs. This discretion also can create problems for transmission providers seeking to comply with our regulations in good faith because so many issues are left for their interpretation, thereby increasing the possibility of disputes with transmission customers and enforcement actions by the Commission.[48] Transmission customers also have found ways to use the tariffs to their own advantage, particularly in the scheduling and queuing processes.[49]

40. As some commenters note, opportunities for undue discrimination persist, particularly in areas where the *pro forma OATT* leaves the transmission provider with substantial discretion. The Commission has a responsibility under section 206 of the FPA to remedy undue discrimination. Indeed, the court concluded in *Associated Gas Distributors* v. *FERC*,[50] that, like the Natural Gas Act,[51] the FPA ''fairly bristles'' with concern over undue discrimination. Based on *AGD*, the Commission determined in Order No. 888 that:

> The Commission has a mandate under sections 205 and 206 of the FPA to ensure that, with respect to any transmission in interstate commerce or any sale of electric energy for resale in interstate commerce by a public utility, no person is subject to any undue prejudice or disadvantage. We must determine whether any rule, regulation, practice or contract affecting rates for such transmission or sale for resale is unduly discriminatory or preferential, and must prevent those contracts and practices that do not meet this standard. * * * *AGD* demonstrates that our remedial power is very broad and includes the ability to order industry-wide non-discriminatory open access as a remedy for undue discrimination.

Order No. 888 at 31,669. Through this Final Rule, the Commission exercises that remedial authority again to limit further opportunities for undue discrimination, by minimizing areas of discretion, addressing ambiguities and clarifying various aspects of the *pro forma OATT*.

41. We disagree with commenters who assert that the Commission is relying on unsubstantiated allegations of discriminatory conduct to justify OATT reform. The courts have made clear that the Commission need not make specific factual findings of discrimination in order to promulgate a generic rule to eliminate undue discrimination.[52] In *AGD*, the court explained that the promulgation of generic rate criteria involves the determination of policy goals and the selection of the means to achieve them and that courts do not insist on empirical data for every proposition upon which the selection depends: ''[a]gencies do not need to conduct experiments in order to rely on the prediction that an unsupported stone will fall.'' [53] During this multi-year proceeding, the Commission has received many comments arguing that commenters have either experienced or perceived that they have experienced unduly discriminatory conduct by transmission providers. Even transmission providers have acknowledged that there is a continuing perception that there is the opportunity for them to unduly discriminate against their competitors and, accordingly, they state their support for our reform effort.[54] Moreover, it is undisputed that the existing *pro forma* OATT provides wide discretion in implementing some of its basic requirements, such as the assessment of whether sufficient ATC exists to grant third party access to the grid and the manner in which new facilities are planned to satisfy third party needs. This wide discretion, when coupled with a transmission provider's incentive to discriminate, creates opportunities for discrimination under the *pro forma* OATT. We have an obligation under section 206 to remedy that discrimination.

42. It is thus clear to us that, notwithstanding the Commission's efforts in Order No. 888, opportunities to engage in undue discrimination can and will persist unless the existing *pro forma* OATT is reformed. We therefore exercise our broad remedial authority today to limit these remaining

[47] Order No. 888 at 31,682.

[48] *See, e.g.*, Order No. 2003 at P 11–12.

[49] *See, e.g.*, Potomac Economics, Ltd., *2004 State of the Market Report: Midwest ISO* at 30–31, 34–35 (Jun. 2005), *http://www.midwestmarket.org/publish/Document/2b8a32_103ef711180_-7bf20a48324a/2004%20MISO%20SOM%20Report.pdf?action=download&_property=Attachment* (explaining that the queuing process, by giving customers the opportunity to submit multiple requests for service, provides a low- or no-cost option that restricts other customers' access to congested interfaces, and the scheduling process, by allowing customers to leave transmission requests unconfirmed, provides a free option that may invite hoarding or result in underutilized capacity).

[50] 824 F.2d 981 (D.C. Cir. 1987) (*AGD*).

[51] 15 U.S.C. 717.

[52] *TAPS* v. *FERC*, 225 F.3d at 667, 688; *National Fuel Gas Supply Corp.* v. *FERC*, 468 F.3d 831 (D.C. Cir. 2006) (*National Fuel*).

[53] 824 F.2d at 1008.

[54] *See, e.g.*, Duke and EEI.

opportunities for undue discrimination. The Commission concludes that any additional costs incurred by transmission providers to implement the reforms required in this Final Rule are fully justified by the need to ensure open, transparent and non-discriminatory access to transmission service. We also believe it is appropriate to adopt these reforms by rulemaking, rather than rely on complaints filed by transmission customers or other parties. Case-by-case application of the reforms adopted in this Final Rule would be inappropriate since the most fundamental problems addressed here arise from deficiencies in the *pro forma* OATT itself, not simply the implementation of the *pro forma* OATT by a few transmission providers. Also, we decline to establish a one-year review period for the reformed *pro forma* OATT, as EPSA recommends. The Commission will continue to actively monitor compliance with its orders and, as necessary, institute further proceedings to meet its statutory obligation to remedy undue discrimination.

43. The Commission will not catalog each and every basis for its reform of the *pro forma* OATT in this section. Rather, we identify the bases for some of the most fundamental reforms herein and, in addition, we explain in each individual section of the Final Rule the inadequacies of the existing *pro forma* OATT provisions being addressed there and the reasons why our reforms are necessary to remedy undue discrimination or otherwise provide for rates, terms and conditions of service under the *pro forma* OATT that are just and reasonable.

B. Lack of Transparency Undermines Confidence in Open Access and Impedes Enforcement of Open Access Requirements

44. Following the issuance of the NOI, the Commission received a number of comments asserting that increased transparency would aid transmission customers in their participation in the wholesale market. A common theme in the comments was that a lack of transparency could lead to claims of discrimination and could make such claims more difficult to resolve. Commenters urged the Commission to improve transparency in a number of areas, particularly the evaluation of ATC and the planning of the transmission system, as well as the processing of transmission service requests and studies.

45. In the NOPR, the Commission agreed that a lack of transparency both increases the potential for undue discrimination and makes it more difficult to detect. The Commission reasoned that this lack of sufficient transparency was caused in part by inadequate compliance with the existing OASIS regulations and in part by inadequate transparency requirements. The Commission stated that the proposed reforms were intended to address both elements of the problem in an effort to increase confidence in open access tariffs and to facilitate compliance with the Commission's regulations and its enforcement of them.

Comments

46. Williams states that its interests have been consistently and significantly compromised by the discretion afforded transmission providers in the interpretation of the OATT and the lack of transparency in requesting, scheduling and interrupting of transmission service. According to Williams, simply being told that service is being curtailed for reliability purposes under opaque local procedures, in the absence of a NERC Transmission Loading Relief (TLR) event, leaves market participants suffering the consequences without knowing on what basis the decision was reached, and without assurance that the decision was made in a non-discriminatory manner. Ultimately, Williams adds, the lack of transparency and latitude taken by the transmission provider to determine which requests for service are confirmed or denied and which are curtailed or interrupted in real time frustrates the Commission's goal of preventing undue discrimination and preference in the provision of transmission service. Furthermore, Williams states, the same lack of transparency exists around the opaque processes utilized, assumptions made, and basis on which the results of transmission planning studies are conducted to grant or deny requests for service.

47. APPA agrees that additional transparency in the administration of public utility transmission providers' OATTs will be of material assistance to both the Commission and transmission customers. However, APPA argues that the Commission must go beyond increasing transparency in the administration of public utility transmission providers' OATTs. According to APPA, more transparency will not change the basic industry paradigm with transmission customers depending on monopoly transmission providers for service. In APPA's view, customers are often reluctant to file complaints or bring problems to the Commission's attention because they depend on their transmission providers' systems for the vital services they need to serve their loads. APPA argues that the Commission not only has an obligation to act to remedy undue discrimination when it sees it, but also has an affirmative duty to look for it. According to APPA, the Commission must continue to actively regulate the transmission services that public utility transmission providers offer, even if full transparency is achieved through the revisions to the OATT implemented in the instant docket.

48. EPSA agrees that greater transparency will help enable market participants and the Commission to monitor and audit the behavior of transmission providers. EPSA states that the several ''black boxes'' shielding discriminatory transmission service over the past ten years must be opened. However, EPSA argues, there must be meaningful clarity and obligations set out in the rules and OATT requirements—transparency simply for the sake of knowing why transmission service has been denied only illuminates a ''bridge to nowhere'' and fails to satisfy the Federal Power Act.

49. Entergy also supports the Commission's efforts to provide greater clarity in the rights and obligations of transmission providers and transmission customers under the OATT. According to Entergy, many of the improvements proposed by the Commission will reduce the likelihood of disputes and promote greater confidence on the part of customers that they are being treated fairly. Entergy states that, while it recognizes that the lack of clarity makes it difficult for the Commission to detect instances of non-compliance by transmission providers, Entergy also believes that this lack of clarity often makes it easier for transmission customers to convert every practice or policy into a claim of discrimination or other misconduct.

50. Although not convinced that there is a compelling need for increased transparency since transmission providers are already required to disclose voluminous amounts of information, Southern states that it recognizes that some reforms in the availability of information may be advantageous. However, Southern asserts, providing additional transparency must not simply impose additional reporting requirements; any such transparency-related reforms should be made after taking into consideration the extent and type of data and information that is already provided.

Commission Determination

51. The Commission concludes that inadequate transparency requirements, combined with inadequate compliance with existing OASIS regulations, increases the opportunities for undue discrimination under the *pro forma* OATT and makes instances of undue discrimination more difficult to detect. We find that the reforms we adopt in this Final Rule will improve transparency in the OATT, reduce opportunities for undue discrimination, and increase our ability to detect undue discrimination.

C. Congestion and Inadequate Infrastructure Development Impede Customers' Use of the Grid

52. The Commission noted in the NOPR that the ability and incentive to discriminate increases as the transmission system becomes more congested. The Commission observed that the *pro forma* OATT contained only minimal requirements regarding transmission planning, which have proven to be inadequate as the Nation faces insufficient transmission investment in many areas. The Commission preliminarily concluded that the inadequacy of the existing obligation to conduct transmission system planning, coupled with the lack of transparency surrounding system planning generally, required reform of the *pro forma* OATT to ensure that transmission infrastructure is constructed on a nondiscriminatory basis and is otherwise sufficient to support reliable and economic service to all eligible customers. The Commission therefore proposed to require public utilities to engage in an open and transparent planning process at both the local and regional levels.

Comments

53. APPA agrees that the lack of adequate transmission infrastructure is one of the core problems facing the electric utility industry. APPA supports revisions to the *pro forma* OATT to enhance and improve transmission planning on both an individual system and regional basis. Several commenters go further, arguing that the proposed reforms are insufficient and urging the Commission to more strongly encourage infrastructure development. EPSA asserts that successful implementation of the Congressional policy in favor of wholesale competition and State policies in favor of competitive procurement is frustrated by the lack of sufficient open access to the transmission grid. According to EPSA, new power plant investment is highly unlikely to occur, except by the transmission provider or its affiliate on a ''sole source'' or ''no bid'' basis (despite Federal and State policies to the contrary), if unaffiliated suppliers cannot effectively and efficiently obtain transmission service. EPSA argues that failure to boldly reform the Commission's open access transmission rules at this critical juncture would effectively hand an undeserved victory to the very transmission providers who, by the Commission's own findings, have the motive and the opportunity to discriminate. International Transmission argues that tariff reform is no substitute for prudent investment in the transmission infrastructure needed to increase the underlying physical capability of the transmission system.

54. On the other hand, some commenters dispute the Commission's assertion in the NOPR that vertically-integrated utilities operating in non-RTO regions have an incentive to discriminate and, therefore, are not adequately expanding the transmission grid to accommodate new entry by more efficient competitors. New Mexico Attorney General argues that vertically-integrated utilities operating under the traditional rate-base, rate-of-return model of regulation in fact have been historically criticized for having incentives to *overbuild*. New Mexico Attorney General asserts that most transmission projects are in reality derailed by strong ''NIMBY'' opposition to the actual siting of transmission lines. Another countervailing factor to the utility's incentive to overbuild, in New Mexico Attorney General's view, is the fact that State regulators attempt to limit capacity investment to reasonable levels only necessary to serve native load.

55. Southern states that the Commission's assertion in the NOPR that vertically-integrated utilities do not have an incentive to expand the grid overlooks the fact that many such utilities are under State legal duties to procure generation supplies through open, non-discriminatory requests for proposals, with the winners of those requests for proposals often being competitors of the vertically-integrated utility. Southern maintains that the winning competitive generation is then integrated into the host utility's transmission system and dispatch, and the transmission system is expanded to ensure the deliverability of this competitive generation. Furthermore, Southern states, a competitive generator can also have the output of its generator planned into the transmission provider's system if it takes long-term firm service under the OATT, with the transmission provider then being under a legal duty to expand its transmission system accordingly. Southern notes that it alone has invested $3.2 billion in transmission over the past decade and plans to invest another $2.8 billion over the next five years (2006–2010).

56. Community Power Alliance also argues that the Commission's own June 2005 ''State of the Markets Report'' contradicts the Commission's assertion that vertically-integrated utilities do not have the proper incentives to expand the grid. Community Power Alliance contends that this report shows that the amount of transmission investments made in the non-RTO regions, where vertically-integrated utilities typically operate, substantially exceeds the amount of transmission investments made in RTO regions.

Commission Determination

57. The Commission concludes that reforms are needed to ensure that transmission infrastructure is evaluated, and if needed, constructed on a nondiscriminatory basis and is otherwise sufficient to support reliable and economic service to all eligible customers. As noted above, vertically-integrated utilities do not have an incentive to expand the grid to accommodate new entries or to facilitate the dispatch of more efficient competitors. Despite this, the existing *pro forma* OATT contains very few requirements regarding how transmission planning should be conducted to ensure that undue discrimination does not occur.

58. Our concern over this flaw is heightened by the critical need for new transmission infrastructure in this Nation. As the Commission explained in the NOPR, transmission capacity is being constructed at a much slower rate than the rate of increase in customer demand, with transmission capacity per MW of peak demand declining at an average rate of 2.1 percent per year during the period 1992 to 2002.[55] The projections suggest that this trend will continue through 2012.[56] As a result, there has been a significant decrease in transmission capacity relative to load in every NERC region.[57] In light of this trend, there is a compelling need to build new transmission and respond to increasing demand through other

[55] Eric Hirst, *U.S. Transmission Capacity: Present Status and Future Prospects* (Aug. 2004), *http://www.eei.org/industry_issues/energy_infrastructure/transmission/USTransCapacity10–18–04.pdf* (Present Status and Future Prospects).

[56] Present Status and Future Prospects at v.

[57] Brendan Kirby (Oak Ridge National Laboratory, U.S. Department of Energy), *Barriers to Transmission Investment*, Technical Conference Presentation, (Docket No. AD05–5–000) (April 22, 2005).

means. EEI estimates that capital spending must increase by 25 percent, from $4 billion annually to $5 billion annually, to ensure system reliability and to accommodate wholesale electric markets.[58] The legacy systems constructed by vertically-integrated utilities prior to the adoption of Order No. 888 support ''only limited amounts of inter-regional power flows and transactions. Thus, existing systems cannot fully support all of society's goals for a modern electric-power system.'' [59]

59. Expansion of the transmission system, as well as more efficient use of the grid, will alleviate the growth of congestion in most regions of the country. Transmission congestion has created fairly small local load pockets in primarily urban areas, *e.g.*, New York City, Long Island, Boston, parts of Connecticut, and the San Francisco Bay Area. Other load pocket concerns have arisen in parts of northern Virginia, and various load centers in SPP. Still other constraints are more regional in scope: from the Midwest to the Mid-Atlantic, from the Midwest to TVA, into and within California, from TVA and Southern into Entergy, from Mid-America Interconnected Network into Wisconsin-Upper Michigan Systems, and into Florida.

60. Transmission congestion can have significant cost impacts on consumers. In 2002, DOE issued a study estimating the costs of congestion in four U.S. regions: California, PJM, New York and New England.[60] DOE found that, despite the overall savings of wholesale electricity markets that lowered consumers' electricity bills by nearly $13 billion annually, interregional transmission congestion cost consumers hundreds of millions of dollars annually. DOE concluded that relieving bottlenecks in these four regions alone could save consumers about $500 million annually.[61] In 2006, DOE released another study identifying two areas of the country with severe existing or growing congestion problems: the Atlantic coastal area from metropolitan New York southward through Northern Virginia, and Southern California.[62]

61. The decline in transmission investment and increase in transmission congestion underscore our concerns over inadequate planning provisions of the existing *pro forma* OATT. The existing *pro forma* OATT, as indicated above, contains very little specificity regarding how transmission planning should be conducted, how customers' needs are incorporated into that process, and what information is publicly available regarding the transmission providers' assumptions, criteria and data used in the planning process. These inadequacies are sufficiently severe, standing alone, to merit reform of the OATT. However, they are of even greater concern given the current state of the transmission grid. With inadequate levels of investment in the grid and increasing transmission congestion, customers' ability to access alternatives to the transmission provider's resources is limited. It is therefore imperative for the Commission to ensure that the planning process under each transmission provider's OATT is sufficient to prevent undue discrimination and transparent enough to detect any remaining instances of undue discrimination. We have done so in the reforms adopted and explained in section V.B.

D. A Consistent Method of Measuring ATC Is Needed

62. Another area in which transmission providers have significant discretion under the *pro forma* OATT is the calculation of ATC. While Order No. 888 obligated each public utility to calculate the amount of transfer capability on its system available for sale to third parties, the Commission did not standardize the methodology for calculating ATC, nor did it impose any specific requirements regarding the disclosure of the methodologies used by each transmission provider.[63] As a result, there are a variety of ATC calculation methodologies in use today and very few clear rules governing their use. Moreover, there is often very little transparency about the nature of these calculations, given that many transmission providers have filed only summary explanations of their ATC methodologies in Attachment C to their OATTs.

63. In the NOPR, the Commission noted that, although the industry has sought to pursue greater consistency in ATC calculations through existing NERC processes, these efforts to date have been largely unsuccessful. The Commission expressed its preliminary determination that the lack of a consistent, industry-wide methodology for calculating ATC gives transmission providers the ability and the opportunity to unduly discriminate against third parties. The Commission therefore proposed a number of reforms to the process of calculating ATC to provide clarity and transparency to users of the grid.

Comments

64. As discussed further in section V.A below, most commenters support the Commission's goal of requiring greater consistency in the manner in which ATC is calculated and additional transparency of ATC calculations. Commenters generally favor the Commission's proposal to increase consistency in the calculation of ATC, including consistent definitions of its components, data inputs, modeling assumptions, and data exchange and coordination protocols. For example, Exelon argues that each ATC component should be used in the same manner for all purposes (*e.g.*, granting transmission service to third parties or for the transmission provider's own network load). Some commenters assert that industry-wide standardization of ATC calculation might not be possible and that the Commission should consider interconnection-wide, regional or even sub-regional standardization. Others suggest allowing flexibility in order to capture differences in system operation, usage, market operations and topology.

65. At the technical conference organized in this proceeding on October 12, 2006 (October 12 Technical Conference), the entire panel agreed that definitions must be consistent and a panelist representing Constellation

[58] *Energy Policy Act of 2005: Hearings before the Subcommittee on Energy and Air Quality of the House Committee on Energy and Commerce*, 109th Congress, First Sess. (2005) (Prepared statement of Thomas R. Kuhn, President of EEI).

[59] Present Status and Future Prospects at v.

[60] U.S. Department of Energy, *National Transmission Grid Study* at 11, 16–17 (May 2002), *available at http://www.ferc.gov/industries/electric/indus-act/transmission-grid.pdf.* To conduct this study, DOE estimated the benefits of interregional wholesale power markets using the Policy Office Electricity Modeling System (POEMS). POEMS is a national energy model designed specifically to examine the impacts of electricity restructuring. The model includes economic, regional, and temporal detail that is needed to analyze the economics of interregional trade. In the first step of the study, DOE used POEMS to examine the cost reductions that would occur if increased electricity transfers across congested paths were allowed in these four regions, assuming generators bid their marginal costs. Under this assumption, consumer costs declined by $157 million per year. In the second step, DOE calculated the increase in congestion costs under the assumption that generators bid above their marginal operating costs when supplies are tight and additional electricity cannot be imported. The price spikes were assumed to occur during hours when at least one transmission link into a sub-region was congested and demand was greater than 90 percent of peak demand. When prices spike an additional $50 per MWh (above the price predicted when generators bid their marginal operating cost) during these periods, congestion costs nearly double to $300 million.

[61] *Id.* at xi and ii.

[62] U.S. Department of Energy, *National Electric Transmission Congestion Study*, Executive Summary at 2 (August 2006), *available at http://www.ferc.gov/industries/electric/indus-act/doe-congestion-study-2006.pdf.*

[63] Order No. 888 at 31,794 n.610.

asserted that broad differences in the core definitions of the ATC calculation are neither rational nor explainable.[64] NERC, however, recognized that the goal of achieving consistency may not mean that a single ATC methodology is required.[65] NERC explained that consistency can be achieved with a limited number of methodologies if the requirements of those methodologies are properly coordinated and communicated.

66. Numerous commenters support the Commission's proposals to increase transparency in the manner in which transmission providers derive ATC, including greater OASIS posting. Commenters opposing the transparency-related reforms focus on the Commission's proposal to require the posting of narratives on OASIS explaining reasons for changes in monthly and yearly ATC values on constrained paths. They argue that such a requirement would be too burdensome and would not provide customers with any significant new information.

67. Several commenters believe that making substantial ATC calculation and modeling data transparent will compromise Critical Energy Infrastructure Information (CEII) but provide suggestions for resolving the issue. Others express concern that the data required for posting on OASIS is not CEII but commercially sensitive. Finally, commenters provide suggestions regarding the requirement to post metrics on OASIS related to the provision of transmission service under the *pro forma* OATT, including various additional metrics the Commission should consider. Others state that this information is already available on OASIS.

Commission Determination

68. We find that the lack of a consistent and transparent methodology for calculating ATC gives transmission providers the ability and opportunity to unduly discriminate in the provision of open access transmission service. There are few clear rules respecting ATC calculation, and transmission providers retain unnecessarily broad discretion in this area. This resulting discretion is a significant problem because calculation of ATC, which varies greatly depending on the criteria and assumptions used, may allow the transmission provider to discriminate in subtle ways against its competitors. On systems where transmission capacity is congested, this lack of consistency, coupled with a lack of transparency, is of heightened importance and has led to recurring disputes over whether the transmission provider is exercising its discretion to discriminate against its competitors. This discretion also hampers the detection of undue discrimination and, thereby, undermines the Commission's ability to enforce the general requirement in Order No. 888 that transmission service be provided on a not unduly discriminatory basis.

69. As discussed more fully below in section V.AIII.D, this Final Rule adopts a number of reforms that address the potential for remaining undue discrimination in the determination of ATC by requiring consistency in how ATC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates ATC.

E. Discriminatory Pricing of Imbalances

70. Order No. 888 focused primarily on the adoption of non-rate terms and conditions of service, rather than instituting broad reform of the Commission's transmission pricing policies. Consistent with this focus, the Commission did not propose broad transmission pricing reform in the NOPR, but rather focused on instances where current pricing practices under the *pro forma* OATT may no longer be sufficient to remedy undue discrimination or ensure just and reasonable rates. One significant reform proposed in the NOPR related to charges for imbalance energy. The Commission preliminarily found that the existing policies provide wide discretion in the development of these charges and hence the potential for undue discrimination. The Commission therefore proposed certain principles to remedy that potential and sought comment on whether a specific imbalance pricing method would be appropriate.

Comments

71. In general, transmission customers complain about the level and scope of energy and generator imbalance charges that are levied under the *pro forma* OATT and under individual interconnection agreements.[66] Customers complain that energy imbalance charges are excessive and not related to the actual costs incurred by transmission providers. They also argue that the inconsistency between these charges in different control areas is unnecessary, and that other means of compensating the transmission provider, such as return-in-kind, should be considered. Generators likewise complain that generator imbalance charges are excessive, that transmission providers refuse to credit generators with the revenues resulting from imbalance penalties that are collected, and that transmission providers prevent unaffiliated generators from purchasing or self-supplying generator imbalance services. In addition, owners of intermittent resources complain that generator imbalance charges, which are imposed to provide an incentive for generators to schedule accurately, are inappropriate given their lack of control and ability to cure deviations.

Commission Determination

72. The Commission agrees that imbalance charges should provide appropriate incentives to keep schedules accurate without being excessive. We also find that consistency in imbalance charges, both between and among energy and generator imbalances, is preferable to the wide variety of imbalance provisions in place today. All imbalances have the same net effect on the transmission system in that they require other generation to be ramped up or down to compensate for the imbalance. As such, the Commission adopts two *pro forma* OATT provisions (Schedule 4 for energy imbalances and Schedule 9 for generator imbalances) based on a tiered structure similar to the imbalance provision used by Bonneville, as described further below. Such an approach recognizes the link between escalating deviations and potential reliability impacts on the system while keeping imbalance charges closely related to incremental costs. The Commission finds, however, that intermittent resources should be exempt from the highest-tier deviation band. We also require transmission providers to credit to all non-offending transmission customers the revenues they collect in excess of incremental costs.

F. Redispatch/Conditional Firm

73. In the NOPR, the Commission examined whether existing methods for evaluating requests for long-term firm point-to-point service continue to be just and reasonable. When a transmission provider considers a new resource to serve native load, the transmission provider does not eliminate an otherwise economic option because the resource may not be

[64] Transcript of October 12 Technical Conference at 149–50, *available at* Preventing Undue Discrimination and Preference in Transmission Service, Technical Conference (Docket No. RM05–25–000).

[65] *Id.* at 125–50.

[66] Energy imbalance charges, including penalties on some systems, are imposed on a transmission customer when the amount of energy scheduled for delivery to the transmission grid does not equal the amount of energy withdrawn by that customer. Generator imbalance charges are levied on generators for deviations between the amount of energy they schedule and the amount they actually deliver to the grid.

deliverable during a few hours of the year. For transmission customers, however, the transmission provider evaluates whether service can be granted in every hour of the year that is modeled and, if not, it informs the customer that service cannot be provided out of existing transfer capability. Only if the transmission customer agrees to pay for facilities studies does the transmission provider evaluate redispatch options, including whether they are less expensive than the upgrade costs. The Commission therefore proposed to reform the existing *pro forma* OATT planning redispatch [67] obligation, or, in the alternative, to add a conditional firm service to the *pro forma* OATT. As proposed by the Commission, conditional firm would have been a long-term service allowing the transmission provider to give a lower curtailment priority than firm to the transmission customer during a pre-specified number of hours.

Comments

74. Some commenters support the inclusion of both a modified planning redispatch obligation and a conditional firm service in the *pro forma* OATT, stating that both are required to remedy undue discrimination and provide for comparable transmission service. These commenters urge the Commission to require transmission providers to offer planning redispatch and conditional firm service and allow customers to choose the option that best suits their physical, commercial and economic circumstances.

75. Others opine that conditional firm service may be simpler and less costly to implement. These commenters prefer the development of conditional firm service over the modifications to the planning redispatch service because of the complexities surrounding redispatch costs and protocols. For example, Entergy believes conditional firm service can provide benefits to transmission customers without unfairly socializing costs to native load and network customers of the transmission provider.

76. On the other hand, many commenters argue that the Commission should not require either option because the services are unnecessary, operationally unworkable, and legally unjustified, or because they would harm reliability and the quality of existing network service and provide disincentives for transmission investment. Several commenters state that these services would make curtailments of existing firm service more likely and limit opportunities for use of secondary network service, thereby harming native load protections and reducing reliability, contrary to FPA sections 215 and 217 respectively. While it recognizes that conditional firm service has been successful in parts of the Western Interconnection, NRECA contends that a mandate would undermine responsible planning and expansion of the transmission grid by harnessing the transmission provider's planning and dispatch functions to frame elaborate service conditions for conditional firm service.

77. Several commenters argue that, if the services are required, the Commission should ensure that reliability is not adversely affected. Others urge the Commission to make the new services an interim option until transmission upgrades are in place to provide firm service. Some commenters believe planning redispatch and conditional firm customers should bear the actual costs of the services received, including costs associated with system operational changes needed to accommodate the services. A few commenters believe that the Commission should allow for regional differences in development of the new services.

Commission Determination

78. The Commission believes it is necessary to modify the manner in which transmission providers assess point-to-point service requests to eliminate the potential for undue discrimination in transmission service. We find that both techniques—planning redispatch and conditional firm service—are currently used under certain circumstances by transmission providers to serve native load and, therefore, that transmission customers should have comparable services in order to avoid undue discrimination, facilitate the provision of long-term transmission service and provide customers with greater flexibility in choosing resources to meet their needs. We expect that both options will help integrate new generation more quickly. This can be particularly beneficial to renewable generation resources, such as wind, that can be constructed more quickly than the transmission upgrades necessary to deliver their power on a firm basis over the long-run.

G. EPAct 2005 Emphasized Certain Policies and Priorities for the Commission

79. Finally, we note that the reforms adopted in this proceeding are consistent with the policies and priorities embodied in EPAct 2005, in which Congress emphasized many of the same principles reflected in this Final Rule. First, in EPAct 2005, Congress placed special emphasis on the development of transmission infrastructure. Congress required the Commission to adopt a rule establishing incentive-based rates for new transmission infrastructure investment. The stated purpose of new FPA section 219 is to benefit ''consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.'' [68] Among other steps, FPA section 219 requires the Commission to ''(1) Promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership of the facilities; (2) provide a return on equity that attracts new investment in transmission facilities (including related transmission technologies); [and] (3) encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities.'' [69] In addition, Congress directed the Commission to encourage the deployment of advanced transmission technologies.[70] Congress also gave the Commission certain ''backstop'' transmission siting authority, and authorized the creation of interstate compacts establishing transmission siting agencies.[71] Finally, the Commission was directed to exercise its authority under EPAct 2005 ''in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the

[67] Although *pro forma* OATT section 13.5 refers to ''redispatch,'' we refer to it here as ''planning redispatch'' to distinguish it from the reliability redispatch provisions in the network integration transmission service sections of the *pro forma* OATT. *See infra* notes 552 and 557.

[68] EPAct 2005 sec. 1241 (to be codified at section 219 of the FPA, 16 U.S.C. 824s). The Commission has issued a Final Rule implementing such an incentive rate program. *See* Order Nos. 679 and 679–A.

[69] FPA Sec. 219(b)(1).

[70] EPAct 2005 sec. 1223 (to be codified at 42 U.S.C. 16442).

[71] EPAct 2005 sec. 1221(a) (to be codified at section 216 of the FPA, 16 U.S.C. 824p). The Commission implemented new regulations in accordance with this section to establish filing requirements and procedures for entities seeking to construct electric transmission facilities in Order No. 689.

service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights * * * on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.'' [72] Although these provisions have been, or will be, addressed primarily in other proceedings, we conclude that the Final Rule is consistent with these provisions because it supports improvements in infrastructure by reforming the transmission planning process to ensure that it is open, transparent and nondiscriminatory.

80. Second, Congress emphasized the need for greater transparency in electricity markets, including transmission service. EPAct 2005 added section 220 to the FPA, which requires the Commission to facilitate ''price transparency in markets for the sale and transmission of electric energy in interstate commerce, having due regard for the public interest, the integrity of [that market], fair competition, and the protection of consumers.'' [73] The Commission was authorized to ''prescribe such rules as the Commission determines necessary and appropriate to carry out the purposes of'' FPA section 220. Those rules ''shall provide for the dissemination, on a timely basis, of information about the availability and prices of wholesale electric energy and transmission service to the Commission, State commissions, buyers and sellers of wholesale electric energy, users of transmission services, and the public.'' This Final Rule similarly will promote greater transparency in the provision of transmission service in many important areas, including ATC calculation and transmission planning.

81. Finally, Congress emphasized compliance with the Commission's regulations, increasing the civil and criminal penalties for violations of Commission-administered statutes and regulations.[74] This new authority buttresses the Commission's efforts to enforce public utility OATTs and the regulations requiring transmission information to be posted on OASIS. As we explained in the Policy Statement on Enforcement, however, this new authority carries with it the responsibility to ensure that enforcement is firm but fair and that our rules are as clear as practicable to facilitate compliance.[75] We conclude that this Final Rule is fully consistent with these principles because it clarifies our rules, in many areas, which will facilitate compliance by transmission providers.

IV. Summary, Scope and Applicability of the Final Rule

82. This section provides a summary of the major components of the Final Rule, a description of the core elements of Order No. 888 that we retain, and a discussion of the applicability of the proposed rule to various entities.

A. Summary of Reforms

83. *Consistency and transparency of ATC calculations*. The Commission affirms the finding in the NOPR that the lack of a consistent, industry-wide methodology for calculating ATC, and the lack of adequate transparency in ATC calculations, increases the potential for undue discrimination and also makes undue discrimination more difficult to detect. The lack of consistent standards can facilitate undue discrimination by giving a transmission provider the discretion, and hence the ability and opportunity, to favor itself and its affiliates over third parties in how it calculates and allocates ATC. In this Final Rule, we give the industry specific guidance regarding the calculation of ATC and establish a firm deadline to develop certain requirements to make more consistent the ATC calculation process and the process of exchanging data between transmission providers about ATC. In addition, we amend *pro forma* OATT requirements as well as our OASIS regulations to increase the transparency in how ATC is calculated.

84. *Requirement for coordinated, open and transparent transmission planning.* The Commission also affirms the finding in the NOPR that Order No. 888 does not contain sufficient protections to guard against undue discrimination in transmission system planning. Without adequate coordination and open participation, market participants have minimal input or insight into whether a particular transmission plan treats all loads and generators comparably. To ensure that truly comparable transmission service is provided by all public utility transmission providers, including RTOs and ISOs, we amend the *pro forma* OATT to require coordinated, open, and transparent transmission planning on both a sub-regional and regional level. To implement this remedy, we adopt the eight planning principles proposed in the NOPR, as well as one additional principle, that each public utility transmission provider will be required to follow. We recognize that many regions have made significant progress in recent years in creating greater openness and transparency in transmission planning and believe our proposed reforms will build upon, strengthen, and improve this progress to reform transmission planning.

85. *Transmission Pricing Reforms*. Consistent with the focus of Order No. 888 on the non-rate terms and conditions of open access, the Commission does not initiate broad reform of transmission pricing policy through this Final Rule. However, we have identified several pricing rules that are part and parcel of OATT service that merit reform.

- *Energy and Generator Imbalance Charges*. We find that energy and generator imbalance charges we have previously accepted are excessive, too varied, and otherwise unrelated to the cost of providing the service and, therefore, we reform energy and generator imbalance pricing. We adopt tiered *pro forma* OATT energy and generator imbalance provisions similar to those in use by Bonneville and exempt intermittent resources from the highest deviation band. In these new provisions, imbalance charges are based on incremental cost and escalate as the imbalance increases. Any deviations from these provisions must be consistent with or superior to the *pro forma* OATT as modified by this Final Rule and must meet the following criteria: the charges must (1) Be related to the cost of correcting the imbalance, (2) be tailored to encourage accurate scheduling behavior, such as by increasing the percentage of the adder as the deviations become larger, and (3) account for the special circumstances presented by intermittent generators, such as by waiving the higher ends of the deviation penalties.
- *Capacity Reassignment Pricing*. We find that the existing cap on the reassignment of point-to-point service is no longer just and reasonable and, therefore, we eliminate the cap. We believe that removing the cap will eliminate an unnecessary impediment to the resale of capacity, which in turn should increase utilization of the grid and otherwise ensure that point-to-point service is just, reasonable, and not unduly discriminatory.

[72] EPAct 2005 sec. 1233(a) (to be codified at section 217(b)(4) of the FPA, 16 U.S.C. 824q). The Commission implemented FPA section 217(b)(4) in *Long-Term Firm Transmission Rights in Organized Electricity Markets*, Order No. 681, 71 FR 43564 (Aug. 1, 2006), FERC Stats. & Regs. ¶ 31,226 (2006), *order on reh'g*, Order No. 681–A, 117 FERC ¶ 61,201 (2006), *reh'g pending*.

[73] EPAct 2005 sec. 1281 (to be codified at 16 U.S.C. 824t).

[74] EPAct 2005 sec. 1284(e)(1) (to be codified at section 316(A) of the FPA, 16 U.S.C. 825o–1).

[75] *Enforcement of Statutes, Orders, Rules and Regulations,* Policy Statement on Enforcement, 113 FERC ¶ 61,068 (2005) (Policy Statement on Enforcement).

• *Crediting of Customer-Owned Facilities.* We retain most elements of our existing policy respecting the crediting of customer-owned facilities, including the requirement that such facilities meet the integration standard. However, we eliminate the requirement that new facilities can receive credits only if they are ''jointly planned'' because this requirement provides a disincentive to coordinated planning. Rather, we provide that such new facilities are eligible for credits if such facilities are integrated into the operations of the transmission provider's facilities. Customer-owned facilities shall be presumed to be integrated if those facilities, if owned by the transmission provider, would be eligible for inclusion in the transmission provider's annual transmission revenue requirement.

86. *Improvements to Point-to-Point Service.* The Commission concludes that the existing methods for evaluating requests for long-term firm point-to-point service are no longer just, reasonable, and not unduly discriminatory. The existing *pro forma* OATT allows the transmission provider to deny a request for long-term point-to-point service if that service is not available in a single hour of the period studied. We find that this approach is not comparable because, when a transmission provider considers a new resource to serve native load, the transmission provider does not eliminate an otherwise economic option because the resource may not be deliverable in a few hours of the year. To remedy this problem, the Commission adopts a ''conditional firm'' component to long-term point-to-point service that addresses the situation where firm service can be provided for most, but not all, hours of the period requested. We also reform the existing requirements for the provision of redispatch service to ensure that they are of greater use to transmission customers and more consistent with reliability planning and operation of the system.

87. *Reform of rollover rights.* The Commission concludes that section 2.2 of the *pro forma* OATT, which grants an ongoing right to transmission customers to renew or ''roll over'' their contracts, should be reformed. The current rollover rights do not provide consistency between the rights of rollover customers and the resulting obligations of transmission providers to plan and upgrade the system to accommodate rollovers. The Commission therefore amends section 2.2 to ensure greater consistency with transmission planning and construction timelines and modifies the minimum term of the rollover rights to five years, rather than the current minimum term of one year. The Commission also requires that a transmission customer eligible for rollover rights provide notice of whether or not it will exercise its right of first refusal to renew the contract no less than one year before the expiration date of the transmission service agreement, rather than within the current 60-day period.

88. *Increases in transparency to lessen the opportunities to discriminate and reduce transaction costs.* In addition to the increased transparency we require regarding the calculation of ATC and transmission planning, we increase the transparency of transmission service provided under the *pro forma* OATT in several other respects. For example, we require transmission providers and their network customers to use the transmission providers' OASIS to request designation of a new network resource and to terminate the designation of an existing network resource. In addition, we require transmission providers to modify their OASIS so that requests to designate and terminate a network resource can be queried, allowing all parties access to such information. We also require transmission providers to post a list of their current designated network resources and all network customers' current designated network resources on their OASIS. Finally, we require transmission providers to post on OASIS all their business rules, practices and standards that relate to transmission services provided under the *pro forma* OATT.

89. *Strengthening enforcement of the pro forma OATT.* The reforms adopted in this Final Rule provide greater clarity in the terms and conditions of the *pro forma* OATT, resolving ambiguities in the existing *pro forma* OATT that have made undue discrimination easier to accomplish and more difficult to detect. Our new civil penalty authority under EPAct 2005 gives us ample power to remedy tariff violations, but it also places upon us an increased responsibility to make the rules as clear as possible. We fulfill that responsibility in the Final Rule by providing greater clarity where appropriate to several critical OATT provisions. We also adopt a number of posting and reporting requirements that will provide the Commission and market participants with information about each transmission provider's performance of *pro forma* OATT obligations. For example, we require transmission providers to post specific performance metrics related to their completion of studies required under the *pro forma* OATT. We note that the Commission will continue to audit compliance with the *pro forma* OATT, and toward that end require transmission information kept on OASIS to be retained for audit purposes for five years. Finally, we adopt a number of reforms to operational penalties assessed under the *pro forma* OATT, including so-called ''over-use'' penalties and the treatment of operational penalty revenues collected from transmission providers and their affiliates.

90. *Miscellaneous OATT improvements.* Finally, we implement a number of improvements to the terms and conditions of the *pro forma* OATT to incorporate the lessons learned over the past ten years. We briefly note these below:

• *Designation of network resources.* We provide clarification regarding the types of agreements that may be designated as network resources, the process for verifying whether agreements meet the requirements in the *pro forma* OATT, and the requirement for transmission providers to designate and undesignate network resources. We also require customers to submit an attestation with each application to designate a new network resource.

• *Reservation priorities.* We change the priority rules to give certain priority to pre-confirmed transmission service requests submitted in the same time period. We also add price as a tie-breaker in determining reservation queue priority when the transmission provider is willing to discount transmission service.

• *Clarifications related to network service.* We provide clarification related to use of network service on an ''as available basis'' and to ''redirects'' of network service.

B. Core Elements of Order No. 888 That Are Retained

91. Although we are adopting many important reforms to Order No. 888 and the *pro forma* OATT in this Final Rule, we emphasize that many of the core elements of Order No. 888 are retained. As the Commission noted in the NOPR, many of these core elements enjoy broad support from many sectors of the industry. A variety of commenters—in response to the NOI issued earlier in this proceeding and again in response to the NOPR—have urged the Commission to focus on meaningful incremental reforms to the *pro forma* OATT, rather than on industry restructuring. We share the view that Order No. 888 can be strengthened without discarding its fundamental structure. We discuss

below the core elements that are being retained and the comments received on these points.

1. Federal/State Jurisdiction

92. In Order No. 888, the Commission stated that it has exclusive jurisdiction over the rates, terms, and conditions of unbundled retail transmission in interstate commerce.[76] Though the Commission adopted a test for determining what constitute Commission-jurisdictional transmission facilities and what constitute State-jurisdictional local distribution facilities in situations involving unbundled wholesale wheeling and unbundled retail wheeling,[77] the Commission stated that it generally would defer to determinations by State regulatory authorities concerning where to draw the jurisdictional line under that test.[78] The Commission declined to assert jurisdiction over bundled retail transmission, reasoning that ''when transmission is sold at retail as part and parcel of the delivered product called electric energy, the transaction is a sale of electric energy at retail.'' [79] The U.S. Supreme Court affirmed the Commission's decision to assert jurisdiction over unbundled but not bundled retail transmission, finding that the Commission made a statutorily permissible choice.[80] In the NOPR, the Commission proposed to retain the jurisdictional divide established in Order No. 888.

Comments

93. Several commenters support the Commission's proposal to retain the existing jurisdictional divide.[81] Though APPA concludes that the most politic course at this juncture is to leave the current jurisdictional boundaries in place and develop cooperative mechanisms in each region to coordinate Federal policy implementation with the relevant State regulators, APPA notes that there is disagreement among its members about whether the current jurisdictional lines are properly drawn. APPA explains that a substantial number of its members believe that all interstate transmission services (both retail and wholesale) should be provided under one consistent set of tariff terms and conditions. Other APPA members, however, believe that the Commission made the proper jurisdictional call in Order No. 888. NARUC urges the Commission to clarify that its planning proposals will not reopen or attempt to change the jurisdictional split over transmission facilities delineated in Order No. 888.

Commission Determination

94. The Commission will retain the existing jurisdictional divide that was established in Order No. 888, which has been affirmed by the U.S. Supreme Court and accepted by the industry and State regulatory authorities.[82] We also reiterate our recognition of the need for heightened cooperation between Federal and State regulators in areas where there are overlapping Federal and State policy concerns. As explained in greater detail in the planning section below, and in response to NARUC's concern, the planning reforms adopted in the Final Rule contemplate coordinated and open transmission planning, but do not reopen or otherwise change the existing jurisdictional divide for transmission facilities.

2. Native Load Protection

95. In Order No. 888, the Commission did not require transmission providers to unbundle transmission service to their retail native load. The Commission also did not require that bundled retail service be taken under the terms of the *pro forma* OATT.[83] Moreover, the Commission allowed a transmission provider to reserve, in its calculation of ATC, transmission capacity necessary to accommodate native load growth reasonably forecasted in its planning horizon.[84] Order No. 888 also granted a rollover right to existing firm service customers,[85] but allowed transmission providers to restrict that rollover right if the capacity was reasonably forecasted as needed to serve native load customers, as long as that restriction was set forth in the customer's initial service contract.[86]

96. Congress, in section 1233 of EPAct 2005, added section 217 to the FPA, entitled ''Native Load Service Obligation,'' which addresses transmission rights held by load-serving entities (LSEs). FPA section 217 allows LSEs to use their own and contracted-for transmission capacity to deliver energy as required to meet their service obligations, without being subject to charges of unlawful discrimination. The provision makes clear, however, that this requirement does not abrogate any contract or service agreement for firm transmission service or rights in effect as of the date of enactment of EPAct 2005.[87] In the NOPR, the Commission concluded that the protection of native load embodied in Order No. 888 is consistent with FPA section 217, and reaffirmed its commitment to the protection of native load.

Comments

97. Several commenters agree with the Commission's preliminary conclusion that the protection of native load embodied in Order No. 888 is consistent with FPA section 217 and support the Commission's continued commitment to the protection of native load.[88] While APPA [89] and TAPS generally agree with the Commission that the overall OATT regime is consistent with section 217, they urge the Commission to maintain and reinforce the comparability requirement. APPA urges the Commission to broaden its preliminary conclusion in the NOPR and conclude instead that the protection of native load *and* the provision of fully comparable transmission service to other LSEs with long-term service obligations, as embodied in Order No. 888, are consistent with FPA section 217. TAPS also supports the Commission's reading of FPA section 217 as consistent with the Order No. 888 *pro forma* OATT's ''native load'' priority, recognizing that FPA section 217 reinforces the OATT's commitment to comparable treatment of all LSEs—*e.g.*, transmission providers and network customers.

98. Other commenters dispute the Commission's preliminary conclusion that the native load protection embodied in Order No. 888 is consistent with FPA section 217.[90] Many commenters argue that FPA section 217 protects all load, not just native load.[91] Constellation states that the Commission must recognize that there are other market participants besides the transmission providers themselves that are LSEs under FPA section 217. Under the definition of LSEs in FPA section

[76] Order No. 888 at 31,781.

[77] *Id.* at 31,771 (setting forth the seven-factor test).

[78] *Id.* at 31,781.

[79] *Id.*

[80] *See New York* v. *FERC*, 535 U.S. at 28.

[81] *E.g.*, Ameren, APPA, North Carolina Commission Reply, PNM–TNMP, and Southern.

[82] *See New York* v. *FERC*, 535 U.S. at 28.

[83] Order No. 888 at 31,745.

[84] *Id.* at 31,694.

[85] *Id.; see pro forma* OATT section 2.2.

[86] Order No. 888–A at 30,198.

[87] 16 U.S.C. 217(f).

[88] *E.g.*, Ameren, E.ON, Tacoma, Arkansas Commission, EPSA, Southern, and TAPS.

[89] APPA argues that the proposed definition of native load customers in section 1.21 is not technically consistent with FPA section 217 because FPA section 217 does not distinguish among the types of power supply arrangements that an LSE must have to enjoy the protection of FPA section 217. Nevertheless, APPA states that it would not be fruitful to reopen the entire OATT framework to address this technical (but very important) definitional difference.

[90] *E.g.*, Arkansas Municipal, Constellation, Duke, Salt River, and South Carolina E&G.

[91] *E.g.*, Constellation, EPSA, and South Carolina E&G.

217, EPSA argues that many entities other than traditional, vertically-integrated utilities are in the business of serving load. The statute, EPSA asserts, applies to any native load service obligation, whether that obligation is served by a competitive supplier, an affiliate of the transmission provider, or by the transmission provider itself. Salt River contends that FPA section 217 is self-implementing, though it urges the Commission to act to remove impediments to the full exercise of rights granted to LSEs.

99. Constellation argues that the Commission should require native load and OATT customers to take service under the same terms and conditions because experience has proven that discrimination has occurred as a result of having two different sets of rules applicable to transmission customers. EPSA urges the Commission to further clarify that the transmission provider has an affirmative obligation to serve native load in a non-discriminatory manner. According to EPSA, section 217 supports the Commission's paramount statutory mission of ensuring non-discrimination and makes clear that a transmission provider, when utilizing transmission capacity or rights reserved to serve native load, must ''put its blinders on'' to ensure that the load's needs are being met in the most economical way available, whether that decision means the deployment of its own affiliated generation, or the deployment of available non-utility alternatives.

100. Arkansas Municipal asserts that FPA section 217 recognizes the need to give priority to LSEs in certain situations, such as when the transmission grid may be constrained and one group of customers may be denied service at the expense of other customers. Arkansas Municipal states that a priority list could be instituted in this reform proceeding that places LSEs at the top of the list in competing requests for transmission service when not all requests could be granted or honored by the transmission provider.

101. New Mexico Attorney General argues that native load is fundamentally different than merchant load and therefore, in the planning process, the needs of merchants should not be treated comparably with the needs of New Mexico utilities' native loads. New Mexico Attorney General asserts that New Mexico utilities have a statutory obligation to serve retail load while merchants are free to come and go with cycles inherent in wholesale markets. According to New Mexico Attorney General, the transmission requirements of the utilities' native loads amount to an ongoing long-term firm contract, while the transmission needs of merchants are, by comparison, short-term and speculative.

102. Several commenters urge the Commission to revisit various aspects of the reforms proposed in the NOPR in order to enhance the protection of native load. For example, some commenters urge the Commission to modify the rollover proposal in the NOPR. Salt River argues that the Commission's regulations must include a clear provision for a transmission owner anticipating, or unexpectedly facing, load growth to recapture capacity temporarily made available to the wholesale market. Arkansas Commission disagrees with the Commission's proposal to require a transmission provider to compete for transmission capacity rather than reclaim it through its rights to reserve capacity for future load growth. The proposal is inequitable, Arkansas Commission argues, because native load customers have historically paid for most of the transmission providers' assets and will continue to do so in the future. Because of this, Arkansas Commission asserts, native load customers should be given preference in the reservation of transmission capacity. In response to Arkansas Commission's position, MDEA urges the Commission to make clear, consistent with the comparability principle adopted in Order No. 888 and reaffirmed in the NOPR, and with FPA section 217, that any reservation of rights or preference available to a transmission provider's native load customers must be available to network customer loads as well. South Carolina E&G argues that the Commission's interpretation of ''reasonably forecasted'' capacity under section 2.2 of the *pro forma* OATT has been effectively impossible to meet and, therefore, the Commission should now provide clear standards for evaluation of native load protecting rollover restrictions. A clear standard, South Carolina E&G states, would have the Commission consider rollover restrictions in light of a utility's transmission planning process. On reply, Progress Energy supports South Carolina E&G's comments. Progress Energy urges the Commission to revisit the rollover rights policy to develop a policy by which an LSE may be assured of future transmission service for reasonably forecasted native load growth.

103. South Carolina E&G also asks the Commission to revise section 13.6 of the *pro forma* OATT, regarding curtailment of firm point-to-point transmission service. South Carolina E&G urges the Commission to comply with the mandate of *Northern States Power Co.* v. *FERC*,[92] which South Carolina E&G asserts held that the Commission had exceeded its authority in rejecting a vertically-integrated transmission provider's proposal to modify section 13.6 of the OATT to give a higher curtailment priority to native load. According to South Carolina E&G, the Commission has responded by applying the court's decision narrowly, but FPA section 217 requires the Commission to change that position and recognize the primacy of service to native load in section 13.6 of the OATT. In its reply comments, Progress Energy supports the comments of South Carolina E&G and states that the Commission must affirmatively recognize the priority of service to LSEs in the application of the curtailment priorities in section 13.6 of the OATT.

104. Duke argues that several of the Commission's proposed reforms—such as hourly firm service, redispatch, and conditional firm service—actually reduce the protection afforded native/network load. Salt River suggests that the Commission should modify its ATC proposal to bring the Commission's native load priority policies in line with FPA section 217. Salt River asserts that, in calculating ATC, the transmission provider must be able to exercise reasonable professional judgment as to the amount of transmission that must be reserved to meet native load service obligations; the Commission should not get into the business of dictating forecasting methodology. Salt River proposes that a native load forecast that is used by an LSE as the basis for committing capital for generation expansion or procurement should be presumed to be valid for purposes of establishing available capacity. EPSA, however, argues that, unless and until the Commission mandates a hard and enforceable definition of ATC, transmission-owning utilities that also own affiliated generation will continue to hide behind the native load service obligation as an excuse for being unable to find ATC for any but self-serving purposes.

105. EPSA also argues that the Commission must ensure that transmission owners' planning accommodates all supply options. EPSA urges the Commission to clarify that transmission capacity reserved for native load is to be made available (including for study and other purposes) to competitive suppliers who wish to

[92] 176 F.3d 1090, 1096 (8th Cir. 1999), *cert. denied sub nom. Enron Power Marketing, Inc.* v. *Northern States Power Co.*, 528 U.S. 1182 (2000).

serve native load as allowed by State law. According to EPSA, all generation assets ultimately serve load and the *pro forma* OATT should be clarified to ensure that the transmission system is available on a non-discriminatory basis now and in the future to ensure that load is optimally served—regardless of which generation resources are serving that load. In its reply comments, EPSA also challenges the initial comments of New Mexico Attorney General, which EPSA argues incorrectly interpret FPA section 217 as drawing a distinction between the types of generation that serve load. EPSA argues that the statute protects the customer load that all suppliers would seek to serve regardless of the source.

106. APPA agrees with the Commission's response in the NOPR to Metropolitan Water District that the specific issues related to an RTO's provision of long-term transmission rights are better left to the rulemaking in Docket Nos. RM06–8–000 and AD05–7–000, and the proceedings in each RTO region to implement the Final Rule issued in those dockets on July 20, 2006. APPA notes, however, that the Commission has not proposed in this docket to exempt RTOs from the provisions of the NOPR. Rather, APPA notes, departures from the *pro forma* OATT, including departures in RTO OATTs, must be justified under the ''consistent with or superior to'' standard. APPA argues that the Commission should apply this standard to long-term transmission rights, as well as to the other terms and conditions of OATT transmission service that RTOs provide.

Commission Determination

107. In Order No. 888, the Commission gave public utilities the right to reserve existing transmission capacity needed for native load growth reasonably forecasted within the utility's current planning horizon. The Commission also allowed transmission providers to restrict rollover rights based on reasonably forecasted need at the time the contract is executed. We continue to believe these protections for native load are appropriate and do not eliminate them in this Final Rule, as suggested by some commenters. We also believe that the protection of native load embodied in Order No. 888, as enhanced by the reforms adopted in this Final Rule, is consistent with FPA section 217, which protects the transmission rights of entities with service obligations to end-users or a distribution utility, to the extent required to meet their service obligations. The additional reforms proposed by commenters are not necessary at this time to remedy undue discrimination. We conclude that the native load priority established in Order No. 888 continues to strike the appropriate balance between the transmission provider's need to meet its native load obligations and the need of other entities to obtain service from the transmission provider to meet their own obligations.

108. In response to comments regarding reforms needed to ATC calculation and transmission planning to bring the native load priority policies in line with FPA section 217, we believe that the Commission's reforms in this Final Rule appropriately reflect the transmission provider's obligation to serve native load. As discussed more fully in the ATC and planning sections below, the processes we adopt herein are open, transparent and non-discriminatory and assume that the transmission provider is meeting its obligations, including its native load service obligation. We disagree with Duke's assertion that the reforms proposed in the NOPR will result in a reduction of the protection afforded native or network load. Not only have we reaffirmed the fundamental protections for native load contained in Order No. 888, but we have modified, where appropriate, the *pro forma* OATT to ensure that a transmission provider's obligations can be met consistent with maintaining the reliability to existing customers, including native load. For example, we are eliminating the current requirement to provide planning redispatch over long periods of time (*e.g.*, 10–30 years) because it is unnecessary to remedy undue discrimination and can create problems in forecasting system conditions consistent with maintaining reliability to native load customers.[93]

109. With regard to APPA's comments regarding long-term transmission rights in organized markets, we note that the Commission has issued its Final Rule in Docket Nos. RM06–8–000 and AD05–7–000.[94] As discussed more fully in the applicability section of this rulemaking, and in response to APPA's comments, we reiterate that any departures from the *pro forma* OATT proposed by an ISO or an RTO must be ''consistent with or superior to'' the *pro forma* OATT in this Final Rule.

[93] Proposals related to other reforms, such as curtailments and rollovers, are discussed in the sections below dealing with each of those issues.

[94] *See supra* note 72.

3. The Types of Transmission Services Offered

110. In Order No. 888, the Commission required all public utilities to offer, on a non-discriminatory, open-access basis, firm network service and firm and non-firm point-to-point service. In the NOPR, the Commission proposed to retain these services and did not propose to require transmission providers to adopt a network contract demand service, either as a replacement for network or point-to-point service or as a third category of service under the OATT.

Comments

111. Several commenters support the Commission's proposal to retain the current services in the *pro forma* OATT and to not adopt contract demand service.[95] While APPA supports the Commission's proposal, it states that the Commission should remain open to individual public utility transmission provider's proposals to add ''hybrid'' service to the base network and point-to-point services.

112. Other commenters, such as AMP-Ohio and Nevada Companies, argue that the Commission should require all transmission providers to offer network contract demand service. Nevada Companies argue that the Commission's network designation process can substantially interfere with State jurisdiction over resource acquisition, especially for transmission providers that are required to purchase substantial amounts of power to serve their retail customers instead of relying primarily on their own generation. Nevada Companies reason that allowing transmission providers to move to a contract demand-based network service would remove them from the dilemma of being forced to make resource procurement decisions that are inconsistent with State requirements. On reply, MidAmerican, Newmont Mining, and Utah Municipals oppose the suggestion that the contract demand service should be made a mandatory service offering in the *pro forma* OATT. In its reply comments, Newmont Mining states that, if the Commission is inclined to provide some relief to allow Nevada Companies to comply with both the *pro forma* OATT and their State-approved resource plans, that relief should come only after an investigation of how similar problems are handled on other systems and should be a narrowly and carefully monitored exception to the resource designation requirements.

[95] *E.g.*, MISO/PJM States, TVA, and Southern.

113. Alberta Intervenors argue that undue discrimination is most likely to occur in situations where there is a single or dominant network customer and that customer either has a dual mandate for serving the network customers or that customer has a ''free option'' for procuring transmission.[96] Alberta Intervenors recommend that the Commission implement standardized rules with respect to the ''free option'' concept while offering regional flexibility to ensure the objectives of open access and the absence of undue discrimination continue to be advanced. Alberta Intervenors also argue that, despite the Commission's proposal to address undue discrimination against transmission customers in attempting to redirect to new receipt and delivery points, undue discrimination remains a concern since network customers retain a flexibility of receipt and delivery points that is not granted to third party point-to-point customers. This flexibility provided to the network customer allows the use of the system for activities known as ''parking'' [97] and ''hubbing.'' [98] Alberta Intervenors urge the Commission to eliminate this unfair competitive advantage under the OATT by making a common service available to all participants rather than differing service for network customers, or alternatively, by restricting the use of point-to-point services by the network customer to exclude its use for ''parking'' and ''hubbing.''

114. MidAmerican states that in the Western Interconnection, a utility's loads are not necessarily located within a confined geographical boundary served by a single transmission owner. In these cases, MidAmerican argues, neither network nor point-to-point service under the current *pro forma* OATT is suitable to serve those loads. To remedy these shortcomings in standard OATT service, MidAmerican states that the Commission should require the incorporation of dynamic scheduling and long-term, seasonally-shaped, firm point-to-point as new service offerings under the *pro forma* OATT.

Commission Determination

115. The Commission will not alter the types of services that we required in Order No. 888. We continue to believe that network and point-to-point services are the appropriate base-line service offerings in the OATT, and we will not mandate that transmission providers adopt new service offerings such as network contract demand service. Although the Commission has accepted forms of network contract demand service proposed by individual transmission providers, and the service may provide benefits to certain customers, we do not believe the service is necessary to remedy undue discrimination. For example, the service would require a departure from full load-ratio pricing for network customers, which may not be warranted to the extent the transmission provider plans its system to serve all native load. However, while the Commission concludes that it will not require all transmission providers to offer this service, in response to the arguments raised by commenters such as AMP-Ohio and Nevada Companies, we reiterate that the Commission already has accepted forms of network contract demand service and will continue to entertain such proposals on a voluntary basis from transmission providers.

116. The Commission also is not persuaded by Alberta Intervenors' and MidAmerican's arguments in support of further alternative services under the *pro forma* OATT. As with network contract demand service, transmission providers may propose such services if appropriate for their region. We do not believe mandating that such services be provided by all transmission providers is necessary at this time to prevent undue discrimination.

4. Functional Unbundling

117. In Order No. 888, the Commission chose to mandate functional, rather than corporate (in which a public utility's transmission and generation assets would be placed in separate corporate entities), unbundling of transmission and generation services. The Commission explained that functional unbundling has three components:

1. A public utility must take transmission services (including ancillary services) for all of its new wholesale sales and purchases of energy under the same tariff of general applicability as do others;
2. A public utility must state separate rates for wholesale generation, transmission, and ancillary services;
3. A public utility must rely on the same electronic information network that its transmission customers rely on to obtain information about its transmission system when buying or selling power.[99]

118. In the years following Order No. 888, a number of public utilities nonetheless underwent corporate unbundling. Many of these entities did so as a result of State-mandated restructuring laws. Others did so for corporate or tax reasons. Some entities divested all of their generation assets to a non-affiliate, while others simply restructured internally to place the generation assets in a different corporate subsidiary than the transmission assets. There remain, however, a significant number of vertically-integrated public utilities that operate under the functional unbundling approach.

119. In the NOPR, we proposed to preserve the functional unbundling approach adopted in Order No. 888, rather than impose a corporate or structural unbundling requirement. While the Commission expressed its continued support for voluntary efforts to adopt structural changes (such as transmission-only companies, RTOs, or other reforms), the Commission found that the more intrusive and costly corporate unbundling was not necessary at this time. The Commission also declined to mandate an independent transmission coordinator for all transmission providers. Though the Commission has previously found that such entities may be appropriate in certain circumstances and we support voluntary efforts to rely on them,[100] the

[96] Alberta Intervenors assert that the purchase of point-to-point service by dominant network customers results in an equal and offsetting reduction to the network customer's network charges, resulting in a net cost of zero. They state that point-to-point service is a net cost to all competitors except the dominant network customer. Thus, they argue, a dominant network customer can buy point-to-point service for an extended period and use this service for a limited number of hours at little (or no) net cost compared to not purchasing point-to-point service for an extended period. In Alberta Intervenors' view, this ''free option'' provides network customers with a competitive advantage when reserving point-to-point service because it enables the network customers to over-consume or buy excess point-to-point service than they would if the true net cost were reflected. Alberta Intervenors contend that such over-consumption reduces access to point-to-point service for other customers.

[97] Alberta Intervenors define ''parking'' as a network customer reserving point-to-point service using a network load point of delivery to purchase energy that it intends to sell but where no buyer has been identified at the time of the reservation. The energy notionally reduces network load. Once a buyer is found, the network customer completes the sale by delivering the energy from freed-up generation at a generation point of receipt to a buyer's point of delivery.

[98] Alberta Intervenors define ''hubbing'' as a practice very similar to ''parking,'' but involving multiple buyers and sellers. The network customer can reserve point-to-point transmission to purchase energy from multiple sellers and to sell energy to multiple buyers by creating a hub within its network load. Alberta Intervenors explain that this allows the network customer to organize purchases and sales by physically matching the requirements of multiple buyers and sellers.

[99] Order No. 888 at 31,654.

[100] *See Duke Power*, 113 FERC ¶ 61,288 (2005); *MidAmerican Energy Co.*, 113 FERC ¶ 61,274 (2005); *see also Entergy Services, Inc.*, 110 FERC 61,295 (2005), *order on clarification*, 111 FERC ¶ 61,222 (2005), *order conditionally approving filing*, 115 FERC ¶ 61,095 (2006).

Commission concluded that there was not a sufficient basis for requiring them as a generic remedy for undue discrimination.

Comments

120. Commenters generally support the Commission's proposal to retain functional unbundling.[101] APPA also supports the Commission's decision not to mandate an independent transmission coordinator for all public utility transmission providers. Similarly, Tacoma supports the Commission's decision to continue to view participation in an RTO or ISO as voluntary actions. While PJM and EPSA would prefer a structural remedy, they generally support the Commission's proposal to retain functional unbundling. However, EPSA states that given the Commission's proposal to continue to rely on functional unbundling, it is critical, particularly in those areas without organized markets, that OATT rules regarding unbundled transmission service be clear, transparent, consistent, and rigorously enforced. APPA states that it will be vital to obtain the cooperation of State regulators in each region where the OATT reforms will be implemented to ensure that the current functional unbundling regime in fact is sufficient to do the job.

121. E.ON and TVA express concern that the Commission may yet choose a structural remedy. E.ON urges the Commission to look at the full depth and breadth of its existing powers to monitor and fully redress any abuses in the allocation of transmission services before considering structural unbundling. Similarly, TVA notes that the Commission already has the option to impose a structural remedy on a case-by-case basis.[102]

Commission Determination

122. The Commission will, as proposed in the NOPR, continue to require functional—rather than corporate or structural—unbundling. As explained in the NOPR, for public utilities that keep transmission and generation assets in the same corporate entity, the Commission has strict Standards of Conduct that require the separation of the utilities' transmission system operations and wholesale marketing functions.[103] These rules require that employees engaged in transmission functions operate separately from employees of energy affiliates and marketing affiliates. A number of information sharing restrictions also apply, which prohibit transmission providers from allowing employees of their energy and marketing affiliates to obtain access to transmission or customer information, except via OASIS.

123. The Commission aggressively enforces the Standards of Conduct and, as referenced by APPA, cooperates with State regulators to ensure that the functional unbundling regime is sufficient to prevent undue discrimination. The Commission's Office of Enforcement is well-suited to investigate potential violations of the Standards of Conduct and to propose remedies, including structural remedies if necessary, to ensure that the separation of functions and information restrictions are fully implemented. We believe that the increased clarity and transparency adopted in other parts of this Final Rule, when coupled with the Standards of Conduct rules and our rigorous enforcement program, will ensure that the functional unbundling requirement will serve its original purpose.

C. Applicability of the Final Rule

1. Non-ISO/RTO Public Utility Transmission Providers

124. In the NOPR, the Commission proposed to apply the Final Rule to all public utility transmission providers, including those that are approved ISOs and RTOs. With respect to non-ISO/RTO transmission providers, the Commission proposed to require all such transmission providers to submit FPA section 206 compliance filings, within 60 days after the publication of the Final Rule in the **Federal Register**, that contain the non-rate terms and conditions set forth in the Final Rule. The Commission also acknowledged that certain non-rate terms and conditions, such as Attachment C (relating to the transmission provider's ATC calculation methodology) and Attachment K (relating to the transmission provider's transmission planning process), may require more than 60 days to prepare and sought comment on an appropriate time period in which to require the submission of these attachments.

125. Following their FPA section 206 compliance filings, the Commission proposed that transmission providers could submit filings under FPA section 205 proposing rates for the services provided for in the tariff, as well as non-rate terms and conditions that differ from those set forth in the Final Rule if those provisions are ''consistent with or superior to'' the *pro forma* OATT.

Comments

126. Several commenters ask the Commission to clarify and/or revise the proposal for dealing with previously-approved provisions that depart from the existing (Order No. 888) *pro forma* OATT. APPA contends that after this multi-phase rulemaking (NOI/NOPR/Final Rule) to revise the OATT, the Commission should hold those public utility transmission providers that propose non-rate terms and conditions differing from the new *pro forma* OATT to a high standard of proof under the ''consistent with or superior to'' standard. According to APPA, any non-rate term and condition that differs from the revised *pro forma* OATT should be ''additive'' in nature (for example, a new service offering, such as network contract demand service) or should propose substantive improvements in transmission service to customers. APPA argues that a public utility transmission provider should not be able to make an FPA section 206 compliance filing to implement the *pro forma* OATT and then ''water down'' its new OATT through an FPA section 205 filing that degrades its transmission service offerings or diminishes the quality of that service.

127. In its reply comments, APPA recommends that the Commission require non-ISO/RTO transmission providers to file the new *pro forma* OATT set out in the Final Rule and add in redline—either in that filing, or a companion one—all previously approved transmission provider-specific

[101] *E.g.*, Santee Cooper, LPPC, TVA, Tacoma, Southern, MISO Transmission Owners, and E.ON.

[102] Some commenters argue that adoption of the ''open dispatch'' proposals raised by commenters such as Chandley-Hogan and PJM would constitute a departure from functional unbundling. We discuss the ''open dispatch'' and similar proposals in section V.C below.

[103] The rules were first established in Order No. 889. *See* Order No. 889 at 31,595. The Standards of Conduct rules were later replaced by a broader set of rules adopted in Order No. 2004, which were subsequently vacated in part by the United States Court of Appeals pending remand proceedings before the Commission. *See Standards of Conduct for Transmission Providers*, Order No. 2004, 68 FR 69134 (Dec. 11, 2003), FERC Stats. & Regs. ¶ 31,155 (2003), *order on reh'g*, Order No. 2004–A, 69 FR 23562 (Apr. 29, 2004), FERC Stats. & Regs. ¶ 31,161 (2004), order on *reh'g*, Order No. 2004–B, 69 FR 48371 (Aug. 10, 2004), FERC Stats. & Regs. ¶ 31,166 (2004), *order on reh'g*, Order No. 2004–C, 70 FR 284 (Jan. 4, 2005), FERC Stats. & Regs. ¶ 31,172 (2005), *order on reh'g*, Order No. 2004–D, 110 FERC ¶ 61,320 (2005), *vacated, National Fuel*, 468 F.3d 831. The Commission has issued an interim rule promulgating temporary regulations consistent with the Court's decision and initiated a further rulemaking to propose permanent regulations. *See Standards of Conduct for Transmission Providers*, Order No. 690, 72 FR 2427 (Jan. 19, 2007), FERC Stats. & Regs. ¶ 31,327 (2007); *Standards of Conduct for Transmission Providers*, Notice of Proposed Rulemaking, 72 FR 3958 (Jan. 29, 2007), FERC Stats. & Regs. ¶ 32,611 (2007) (Standards of Conduct NOPR).

provisions. APPA states that transmission providers should then explain whether they propose to include these provisions in their revised OATTs, why they propose to retain or delete these provisions, and whether they believe these provisions are ''affected by the revisions adopted in the Final Rule.''

128. In contrast, Duke and EEI ask the Commission to clarify that transmission providers with previously-approved departures from the OATT that are not related to the reforms adopted in this Final Rule will not be required to rejustify these provisions in their FPA section 206 compliance filings. They also ask that transmission providers not be required first to adopt all of the provisions of the revised *pro forma* OATT and then make an FPA section 205 filing to refile a departure previously approved by the Commission. They recommend that existing, approved departures from the *pro forma* OATT that are not affected in a substantive way by the changes to the *pro forma* OATT should be included in the initial FPA section 206 filing.[104] On reply, Indianapolis Power agrees with Duke and EEI and urges the Commission to consider the unwieldy and cost prohibitive nature of a process that would require transmission providers to demonstrate that previously-accepted elements of their OATTs are acceptable.

129. Duke and EEI, in their reply comments, argue that APPA's approach would be inefficient and would cause a substantial disruption to transmission service because both transmission providers and transmission customers would be required to abandon tariff provisions that the Commission has previously found to be consistent with or superior to the *pro forma* OATT and that are regularly being used. For example, Duke notes, Duke Carolina has an Attachment K that covers the Independent Entity that will oversee the provision of transmission service by Duke. Duke asserts that a literal interpretation of the NOPR proposal would mean that it would have to delete this attachment and replace its entire OATT with the revised *pro forma* OATT and then refile its entire Independent Entity proposal with its FPA section 205 filing. Similarly, Entergy states that it currently has a *pro forma* Generator Imbalance Agreement in place that was agreed to by the IPPs on its system and accepted by the Commission. Entergy urges the Commission to permit transmission providers to propose their own imbalance pricing methodology as long as the proposed generator imbalance charges are consistent with or superior to the generator imbalance provisions ultimately adopted in the OATT.

130. On reply, NRECA opposes EEI's compliance proposal. NRECA states that the Commission should retain the two-phased compliance procedure proposed in the NOPR because it strikes a fair balance by providing transmission providers the opportunity to suggest changes to their *pro forma* OATTs under FPA section 205, while allowing transmission customers and others the opportunity to argue that the deviations from the new *pro forma* OATT are neither consistent with nor superior to the *pro forma* OATT.

131. NRECA acknowledges that there will be a burden on the transmission provider to prepare a compliance filing; however, it urges the Commission to retain its proposal and require transmission providers to identify those terms and conditions that differ from the *pro forma* OATT. NRECA agrees that, if a term or condition unrelated to any modification of the *pro forma* OATT in the instant rulemaking has already been found to be consistent with or superior to the existing Order No. 888 *pro forma* OATT, it likely continues to be consistent with or superior to the revised *pro forma* OATT term or condition. NRECA argues, however, that a public utility transmission provider should still be required in a compliance filing to identify these deviations from the revised *pro forma* OATT and, ultimately, to justify them in the event that they are fairly contested. Otherwise, NRECA contends, the Commission and industry lose the consistency and related advantages the *pro forma* OATT seeks to provide.

132. Several commenters addressed the deadlines proposed in the NOPR. APPA suggests that the Commission set a 60 or 90-day deadline for those provisions the transmission provider can complete itself and a 120 or 180-day deadline for those provisions and attachments that will require the transmission provider to incorporate regional practices and protocols, such as Attachments C and K. Tacoma proposes 180 days for transmission providers to submit Attachments C and K. PGP recommends that transmission providers be given one year to file Attachment K.

133. EEI and National Grid urge the Commission to align the compliance filing deadlines for ISOs and RTOs and their transmission-owning members in order to eliminate any potential confusion and to enhance coordination within the ISOs and RTOs. To the extent that public utility transmission owners whose transmission facilities are under the control of RTOs and ISOs have filing rights under the RTO or ISO tariffs, EEI asks that such public utility transmission owners be required to submit any necessary tariff filings within 90 days after the effective date of the Final Rule, rather than the currently-proposed 60 days. National Grid suggests that the Commission establish a single deadline for ISOs/RTOs and their transmission-owning members, set at six months from the date of publication of the Final Rule.

134. TDU Systems recommend that the Commission adopt a staggered filing approach for the compliance filings (*i.e.*, have transmission providers come in at different times based on criteria chosen by the Commission, such as alphabetically or by size). TDU Systems argue that this would ensure that transmission customers are not forced to review all of their transmission providers' filings at the same time.

Commission Determination

135. The Commission adopts the two-tiered implementation process proposed in the NOPR, with certain clarifications and modifications, as discussed below. As the Commission proposed in the NOPR, all transmission providers that have not been approved as ISOs or RTOs, and whose transmission facilities are not under the control of an ISO or RTO, are required to submit FPA section 206 compliance filings that contain the revised non-rate terms and conditions set forth in the Final Rule, within 60 days after the publication of the Final Rule in the **Federal Register**.[105] However, this filing only need to contain the revised provisions adopted in the Final Rule, rather than the transmission provider's entire *pro forma* OATT.[106] After the submission of their

[104] Duke and EEI propose that a utility would redline its compliance filing OATT against the revised *pro forma* OATT so that the Commission can readily identify the ''already-approved'' differences.

[105] The Commission clarifies that existing waivers of the obligation to file an OATT or otherwise offer open access transmission service in accordance with Order No. 888 shall remain in place. The reforms to the *pro forma* OATT adopted in this Final Rule therefore do not apply to transmission providers with such waivers, although we expect those transmission providers to participate in the regional planning processes in place in their regions, as discussed in more detail in section V.B. Whether an existing waiver of OATT requirements should be revoked will be considered on a case-by-case basis in light of the circumstances surrounding the particular transmission provider.

[106] As explained below, the Commission is not requiring transmission providers to submit in their compliance filing tariff sheets associated with provisions of the *pro forma* OATT that have not been modified in this proceeding. To the extent, however, a transmission provider desires to refile its entire OATT in order to simplify pagination or other tariff designation issues associated with

FPA section 206 compliance filings, these transmission providers may submit FPA section 205 filings proposing rates for the services provided for in the tariff, as well as non-rate terms and conditions that differ from those set forth in the Final Rule if those provisions are ''consistent with or superior to'' the *pro forma* OATT.

136. The Commission recognizes that, since the issuance of Order No. 888, some non-ISO/RTO transmission providers have received approval from the Commission to adopt variations from the non-rate terms and conditions of the *pro forma* OATT that are consistent with or superior to the Order No. 888 *pro forma* OATT. Under the compliance procedure adopted above, those variations that are not affected in a substantive manner by the reforms to the *pro forma* OATT adopted in this Final Rule may remain in place. We disagree with the implementation procedures proposed by APPA, which would require non-ISO/RTO transmission providers with provisions in their OATTs that depart from the *pro forma* OATT, but which are not substantively affected by the reforms in this NOPR, to make a filing that explains whether and why they would retain or delete these provisions. We see no need to require non-ISO/RTO transmission providers to ''rejustify'' such provisions if they are not substantively affected by the reforms in this Final Rule, given that the Commission has already found these provisions to be consistent with or superior to terms and conditions set forth in the *pro forma* OATT that remain unchanged, and the Commission has not otherwise found these provisions to be unjust and unreasonable.

137. In other circumstances, however, non-ISO/RTO transmission providers may have provisions in their existing OATTs that the Commission deemed to be consistent with or superior to terms and conditions of the Order No. 888 *pro forma* OATT that are being modified by the Final Rule. Such transmission providers must demonstrate that these previously-approved variations continue to be consistent with or superior to the *pro forma* OATT as modified by the Final Rule. We continue to believe that use of the ''consistent with or superior to'' standard is appropriate when reviewing variations from the *pro forma* OATT and reject APPA's proposal to adopt a higher burden of proof.

138. The two-tiered compliance process adopted above will allow transmission providers with previously-approved variations an opportunity to show that their existing deviations continue to be consistent with or superior to the *pro forma* OATT as modified in the Final Rule. However, the Commission recognizes that it may cause disruption for some transmission providers that wish to continue to rely on previously-approved variations during the compliance process. The Commission therefore offers an optional implementation process for non-ISO/RTO transmission providers seeking approval of previously-approved variations.

139. Transmission providers that have not been approved as ISOs or RTOs and whose transmission facilities are not under the control of an ISO or RTO may submit an FPA section 205 filing, within 30 days after the publication of the Final Rule in the **Federal Register**, seeking a determination that a previously-approved variation from the Order No. 888 *pro forma* OATT that has been substantively affected by the reforms adopted in this Final Rule continues to be consistent with or superior to the revised *pro forma* OATT adopted here.[107] Each applicant should request that the proposed tariff provisions be made effective as of the date of the transmission provider's section 206 compliance filing, to be submitted within 60 days after the publication of the Final Rule in the **Federal Register** (as provided above). As a condition of that request, however, the transmission provider should state that the Commission has 90 days following the date of submission of the filing to act under section 205. In other words, the Commission is offering this optional implementation process to applicants that allow the Commission 90 days to act on the filing. This procedure will streamline the compliance process by allowing existing variations from terms and conditions of the *pro forma* OATT that have been modified by the Final Rule to remain in effect until further Commission action, while also providing the Commission with adequate time to act on the filings. The subsequent section 206 compliance filing would then contain tariff sheets necessary to implement the remaining modifications required under the Final Rule, *i.e.*, modifications related to tariff provisions that did not implicate previously-approved variations.

140. As the Commission acknowledged in the NOPR, certain non-rate terms and conditions, such as Attachment C (relating to the transmission provider's ATC calculation methodology) and Attachment K (relating to the transmission provider's transmission planning process) may require more than 60 days to prepare. Accordingly, we will require non-ISO/RTO transmission providers to file their Attachment C within 180 days after the publication of the Final Rule in the **Federal Register** and their -Attachment K (or the transmission providers' equivalent thereof) within 210 days after the publication of the Final Rule in the **Federal Register**. A summary of the more significant filing requirements established in this Final Rule is provided in Appendix A.[108]

141. Other reforms adopted in the Final Rule will involve coordination with the North American Energy Standards Board (NAESB) to establish OASIS functionality or uniform business practices. The Commission requests that NAESB file a status report within 90 days of publication of the Final Rule in the **Federal Register** that contains a work plan for development of such OASIS functionality and business practices. This work plan should indicate, for each reform, what actions are necessary and an estimate of the timeframe for completing those actions. Pending resolution of these issues with NAESB, the Commission requires that each transmission provider develop its own OASIS functionality or business practice necessary to implement each such reform within 90 days of publication of the Final Rule in the **Federal Register**, unless a different compliance requirement is otherwise specified in this Final Rule. Upon review of this work plan, the Commission will issue an order establishing further compliance deadlines as necessary.

142. We are not persuaded to adopt a staggered compliance filing approach in this proceeding as TDU Systems suggest. However, we will align the compliance filing deadlines for ISOs and RTOs and their transmission-

implementing the modifications required under the Final Rule, it may do so. We note that such a filing is a compliance filing and, therefore, the only deviations in this filing should be the revised provisions in this Final Rule. If a transmission provider wishes to propose different terms and conditions, it must make a separate FPA section 205 filing.

[107] Transmission providers must provide citations to the Commission orders where the variation was accepted by the Commission as consistent with or superior to the *pro forma* OATT.

[108] For further information related to the Final Rule, such as electronic versions of the *pro forma* OATT showing tariff changes adopted in the Final Rule in redline/strikeout format, and further information regarding docketing of compliance filings and specific filing instructions, please visit our Web site at the following location *http://www.ferc.gov/industries/electric/indus-act/oatt-reform.asp*.

owning members in order to eliminate any potential confusion and to enhance coordination within the ISOs and RTOs. Thus, we will require public utility transmission owners whose transmission facilities are under the control of RTOs and ISOs to make any necessary tariff filings required to comply with the Final Rule within 210 days after the publication of the Final Rule in the **Federal Register**.

2. ISO and RTO Public Utility Transmission Providers and Transmission Owner Members of ISOs and RTOs

143. With respect to an ISO or RTO public utility transmission provider, the Commission recognized in the NOPR that such an entity may already have tariff terms and conditions that are superior to the *pro forma* OATT. The Commission also noted that the purpose of this rulemaking is not to redesign approved, fully-functioning RTO or ISO markets. Thus, the Commission proposed to require ISO and RTO transmission providers to submit FPA section 206 compliance filings, within 90 days after the publication of the Final Rule in the **Federal Register**, that contain the non-rate terms and conditions set forth in the Final Rule or that demonstrate that their existing tariff provisions are consistent with or superior to the revised provisions to the *pro forma* OATT. The Commission also proposed to allow ISO and RTO transmission providers, after making their FPA section 206 compliance filings, to submit filings under FPA section 205 proposing rates for the services provided for in their tariffs, as well as non-rate terms and conditions that differ from their existing tariffs and those set forth in the Final Rule if those provisions are consistent with or superior to the *pro forma* OATT. The Commission did not address the specific obligations of transmission owning members of ISOs and RTOs.

Comments

144. Several commenters support applying the revised *pro forma* OATT to ISOs and RTOs and requiring ISOs and RTOs to justify any variations therefrom. MidAmerican argues that universal application of the revised *pro forma* OATT is important because not every ISO or RTO transmission provider has existing tariff terms and conditions that are consistent with or superior to the OATT. Old Dominion also supports the Commission's compliance proposals for ISOs and RTOs. NRECA similarly states that RTOs, ISOs and ITCs should not be automatically exempt from any aspect of the rules governing open access transmission service, including the planning requirements. APPA asserts that in their filings, RTOs should be required to show how their transmission service packages, including features such as long term transmission rights, ancillary services, and treatment of losses, are consistent with or superior to the newly revised *pro forma* OATT. Moreover, APPA argues, the Commission should not allow RTOs to use their avowed independence as a justification for transmission services that in fact do not meet the consistent with or superior to standard.[109]

145. On the other hand, numerous commenters argue that the proposed compliance process is burdensome and could require ISOs and RTOs to have to relitigate already-approved OATT provisions. The ISOs and RTOs generally argue that, given the nature of the services they offer, many of the proposed revisions do not apply to their OATTs. Many commenters urge the Commission to adopt a more limited compliance filing process. Some commenters, for example, argue that the Commission should only require ISOs and RTOs to submit compliance filings that are limited to the specific *pro forma* tariff revisions set forth in the Final Rule. Duke argues that ISOs and RTOs should only be required to make a single filing that revises their OATTs in a manner that takes into account the nature of the OATT service provided by that ISO or RTO and whether a reform adopted in the Final Rule is relevant to the ISO's or RTO's OATT. EEI urges the Commission to require ISOs and RTOs to adopt only those OATT reforms that are necessary to improve the quality of transmission service that is provided by an ISO or RTO. EEI adds that those who protest an ISO's or RTO's assertion that an existing provision is consistent with or superior to the revised *pro forma* OATT should have the burden to demonstrate otherwise. The ISOs and RTOs similarly argue that, absent a specific demonstration that an ISO's or RTO's OATT provisions are unjust and unreasonable, the compliance filing requirements should not apply to ISOs and RTOs.

146. EEI urges the Commission to clarify that the 90-day filing should include the following materials: Revisions of tariff provisions that conform to the revisions in the *pro forma* OATT that are appropriate, given the ISO or RTO's market structure; statements supporting the provisions of the tariff that the ISO or RTO believes are consistent with or superior to the revised *pro forma* OATT; and justifications that support excluding revisions of the provisions that the ISO or RTO believes are not consistent with or superior to the revised *pro forma* OATT. EEI also interprets the NOPR proposal to mean that an ISO or RTO immediately may make a separate filing proposing further modifications, including revisions to the newly-effective provisions of the *pro forma* OATT, that are consistent with or superior to the just-filed modifications.

147. SPP urges the Commission to affirm that ISOs and RTOs will not be required to rejustify their previously-approved non-*pro forma* tariff provisions, but rather only the new or revised tariff provisions expressly prescribed in the Final Rule. In its reply comments, SPP notes that the terms and conditions of its OATT are interrelated and work together to achieve a system of administration that fosters open and transparent transmission service and function as an integrated whole. Therefore, SPP asserts, the modification of one provision of its OATT will impact several other provisions and the process of rejustifying one aspect of the tariff likewise will implicate other terms and conditions.

148. Indianapolis Power argues that tariff changes resulting from this rulemaking should be included only with the support of the ISO and RTO members who bear the costs and are in the best position to judge the benefits.

149. On reply, ISO/RTO Council generally argues that there is no factual or legal support for the ISO/RTO compliance procedures advocated by commenters such as APPA. ISO/RTO Council states that the OATTs of ISOs and RTOs were developed through extensive stakeholder procedures and subject to the Commission's filing, notice, comment, and approval processes under FPA section 205. ISO/RTO Council asserts that to adopt the post-hoc, open-ended review advocated by these parties would give disgruntled participants a ''second bite'' at legally effective OATT terms and would undermine the very stakeholder and regulatory processes by which ISOs and RTOs were established. MISO in particular argues that APPA's proposal ignores that ISO and RTO tariffs have already been determined to be just and reasonable and consistent with or superior to the Order No. 888 *pro forma* OATT, is profoundly inconsistent with the Commission's policy of encouraging RTOs as an option to ensure non-discriminatory open access transmission service, and is impracticable unless the intent is to grind RTO markets to a halt. MISO states that each RTO tariff has

[109] *See also* CMUA Reply.

dozens, or perhaps hundreds, of Commission-approved deviations and, in its view, reopening these issues would not be in the public interest and would consume enormous resources of both the RTOs and the Commission.

150. Southern, in its reply comments, argues that ISOs and RTOs are essentially requesting to be exempted from the requirements of this proceeding. Southern states that all transmission service revisions/reforms adopted in this proceeding should apply uniformly to all transmission providers, including ISOs and RTOs. Southern contends that ISOs and RTOs are increasingly subject to complaints alleging discriminatory treatment and asserts that the highly partisan attacks made by several RTOs against vertically-integrated utilities further calls into question whether ISOs and RTOs are not susceptible to taking discriminatory actions. In addition, Southern argues, such exemptions would likely result in seams issues.

151. Some commenters state that the Commission should identify the specific reforms it will apply to RTOs and ISOs and provide more general guidance as to how it intends to apply the consistent with or superior to standard to ISO/RTO tariff provisions. National Grid asserts that the Commission properly identified these provisions in the NOPR when the Commission concluded that there may be elements of the proposed reforms that are superior to what currently exist in some RTOs or ISOs, *e.g.*, transparency, data exchange, or planning. MISO/PJM States identify six areas as potentially applicable to RTOs: Hourly firm transmission service; obligation to expand capacity; joint ownership; reservation priority; ancillary services; and *pro forma* OATT definitions. MISO/PJM States also identify eleven areas as not applicable to RTOs: Undue discrimination generally; transmission pricing; remedies, penalties and enforcement; changes in receipt and delivery points (redirects); rollover rights; rules, standards and practices governing the provision of transmission service; joint transmission planning; tariff compliance review; hoarding of transmission capacity; curtailments; and ancillary services. APPA, in its reply comments, opposes granting a blanket exemption for ISOs and RTOs from any portion of the compliance filing requirement.

152. CAISO urges the Commission to clarify how it should provide for changes in the Final Rule to transmission services that it does not provide or which are clearly incompatible with the transmission service model it employs. In their reply comments, CMUA and APPA oppose this request for clarification. CMUA argues that CAISO's failure to provide any long-term transmission service renders its transmission service markedly inferior to the firm transmission service under the *pro forma* OATT. CMUA maintains that, instead of affirmatively embracing its obligation to show that its transmission service offering, once supplemented with long-term transmission rights that fully comply with all seven guidelines set out in Order No. 681, will meet the ''consistent with or superior to'' standard of Order No. 888, CAISO instead asks to be exempted from any such requirement.

153. Xcel and Indicated New York Transmission Owners assert that the Commission should allow regional variations to the extent that ISOs/RTOs can demonstrate that their OATT provisions meet the objectives of the Final Rule. Xcel argues that the consistent with or superior to standard may be too narrow because some changes to the OATT made by ISOs/RTOs are not as much ''superior'' or ''consistent with,'' as they are simply necessary because the tariff is regional. Indicated New York Transmission Owners argue that the Commission should not impose a consistent with or superior to standard generally reserved for transmission providers that are not members of an ISO/RTO. Indicated New York Transmission Owners assert that, to the extent that certain improvements could or should be made to the ISO/RTO OATTs, the Final Rule should permit the necessary flexibility for each ISO/RTO to propose and adopt such changes through their stakeholder governance processes, in order to address the unique market features and circumstances of each region.

154. PJM urges the Commission to include an ''independent entity variation'' standard similar to that used in Order No. 2003, which permitted an RTO to adopt interconnection procedures that are responsive to specific regional needs. NRECA responds that the Commission should not entertain PJM's request. While PJM's requested standard may have made sense in the context of generator interconnections, NRECA contends that it is inapposite to reform of the OATT. NRECA states that ISOs and RTOs should not be allowed to keep on file tariff provisions that possess the potential to allow for undue discrimination, even if the entity publishing the tariff is ostensibly independent of market participants and even if the proposed reforms do not directly improve the ''quality of'' transmission service, since the purpose of this rulemaking is to prevent undue discrimination in the provision of transmission service.

155. To whatever extent the Commission elects to exempt RTOs and ISOs from certain aspects of the *pro forma* OATT, E.ON asserts that the same consideration should be given to utilities that have entered into arrangements with alternative, Commission-approved, independent transmission organizations. In their reply comments, TDU Systems oppose this proposal arguing that these alternative constructs may not meet the independence criteria of Order Nos. 888 and 2000.

156. Several commenters urge the Commission to extend the proposed 90-day deadline for ISOs and RTOs to submit their compliance filings. EEI recommends that the Commission clarify that it will grant an extension of time if the stakeholder process prevents an ISO or RTO from obtaining stakeholder approval of tariff changes within the 90-day deadline. SPP requests a minimum of 120 days for compliance. National Grid and MISO (in its reply comments) propose that the Commission establish a single deadline for ISOs/RTOs and their transmission-owning members set at six months from the date of publication of the Final Rule.

Commission Determination

157. The Commission adopts the compliance procedures proposed in the NOPR, with certain revisions and clarifications. We will require ISO and RTO transmission providers to submit FPA section 206 compliance filings, within 210 days after the publication of the Final Rule in the **Federal Register**, that contain the non-rate terms and conditions set forth in the Final Rule or that demonstrate that their existing tariff provisions are consistent with or superior to the revised provisions of the *pro forma* OATT. As with non-ISO/RTO transmission providers, however, we will not require ISO and RTO transmission providers to ''rejustify'' existing provisions in their OATTs that are not affected in a substantive manner by the revisions to the *pro forma* OATT in the Final Rule. As we explained above, we find that such a process is unnecessary, given that we have already found these provisions to be consistent with or superior to the Order No. 888 *pro forma* OATT and these provisions are not substantively affected by the reforms we adopt today.

158. We also recognize, as we did in the NOPR, that some of the changes adopted in the Final Rule may not be as relevant to ISO/RTO transmission

providers as they are to non-independent transmission providers. For example, many ISOs and RTOs use bid-based locational markets and financial rights to address transmission congestion, rather than the first-come, first-served physical rights model set forth in the *pro forma* OATT. As we indicated in the NOPR, nothing in this rulemaking is intended to upset the market designs used by existing ISOs and RTOs. We also recognize that ISOs and RTOs may well have adopted practices that are already consistent with or superior to the reforms adopted here. For example, ISOs and RTOs tend to have transmission planning processes that are significantly more open and transparent than the processes used by non-independent transmission providers. We encourage ISOs and RTOs to meet with their stakeholders to discuss whether any improvements are necessary to comply with the Final Rule.

159. We reject Indianapolis Power's proposal to require tariff changes resulting from this rulemaking only with the support of the ISO and RTO members who may bear the costs associated with the revision. Indianapolis Power effectively asks that we allow ISO and RTO members to veto our decisions here, which is contrary to our duty to prevent undue discrimination in the provision of transmission service.

160. Regarding CAISO's request for clarification of how it should address changes in the Final Rule to transmission services that it does not provide or which are incompatible with its service model, we reiterate that CAISO—like any other ISO or RTO—has the opportunity to demonstrate that a variation from the tariff revisions adopted in the Final Rule satisfies the consistent with or superior to standard. We do not believe that the adoption of an ''independent entity variation,'' proposed by PJM, or a regional variation standard, proposed by Xcel and Indicated New York Transmission Owners, would be appropriate. Again, the Commission finds that the reforms adopted in this Final Rule are necessary to prevent undue discrimination in the provision of transmission service and any transmission provider, including an ISO or RTO, must demonstrate that variations from the tariff modifications required here satisfy the consistent with or superior to standard.

161. As discussed above, however, we will align the compliance filing deadlines for ISOs and RTOs and their transmission-owning members and require public utility transmission owners whose transmission facilities are under the control of RTOs or ISOs to make any necessary tariff filings required to comply with the Final Rule within 210 days after the publication of the Final Rule in the **Federal Register**. A summary of the more significant filing requirements established in this Final Rule is provided in Appendix A.[110]

3. Non-Public Utility Transmission Providers/Reciprocity

162. In Order No. 888, the Commission conditioned non-public utilities' use of public utility open access services on an agreement to offer comparable transmission services in return.[111] The Commission found that, while it did not have the authority to require non-public utilities to make their systems generally available, it did have the ability and the obligation to ensure that open access transmission is as widely available as possible and that Order No. 888 did not result in a competitive disadvantage to public utilities.

163. Under the reciprocity provision in section 6 of the *pro forma* OATT, if a public utility seeks transmission service from a non-public utility to which it provides open access transmission service, the non-public utility that owns, controls, or operates transmission facilities must provide comparable transmission service that it is capable of providing on its own system. Under the *pro forma* OATT, a public utility may refuse to provide open access transmission service to a non-public utility if the non-public utility refuses to reciprocate. A non-public utility may satisfy the reciprocity condition in one of three ways. First, it may provide service under a tariff that has been approved by the Commission under the voluntary ''safe harbor'' provision. A non-public utility using this alternative submits a reciprocity tariff to the Commission seeking a declaratory order that the proposed reciprocity tariff substantially conforms to, or is superior to, the pro forma OATT. The non-public utility then must offer service under its reciprocity tariff to any public utility whose transmission service the non-public utility seeks to use. Second, the non-public utility may provide service to a public utility under a bilateral agreement that satisfies its reciprocity obligation. Finally, the non-public utility may seek a waiver of the reciprocity condition from the public utility.[112]

164. In EPAct 2005, Congress authorized, but did not require, the Commission to order non-public utilities (or ''unregulated transmitting utilities'') to provide transmission services under a new section 211A in Part II of the FPA. This section states in part that the Commission ''may, by rule or order, require an unregulated transmitting utility to provide transmission services'' at rates that are comparable to those it charges itself and under terms and conditions (unrelated to rates) that are comparable to those it applies to itself, and that are not unduly discriminatory or preferential. The language does not limit the Commission to ordering transmission services only to the public utility from whom the non-public utility takes transmission services, but rather permits the Commission to order the non-public utility to provide ''open access'' transmission service, *i.e.*, service to all eligible customers.

165. In the NOPR, the Commission proposed to retain the current reciprocity language in the *pro forma* OATT, as well as Order No. 888's three alternative provisions for satisfying the reciprocity condition, *i.e.:* A non-public utility that owns, controls, or operates transmission and seeks transmission service from a public utility must either satisfy its reciprocity obligation under a bilateral agreement, seek a waiver of the OATT reciprocity condition from the public utility, or file a safe harbor tariff with the Commission.[113]

166. The Commission did not propose a generic rule to implement the new FPA section 211A.[114] Rather, the Commission proposed to apply its provisions on a case-by-case basis, such as when a public utility seeks service

[110] For further information related to the Final Rule, such as electronic versions of the *pro forma* OATT showing tariff changes adopted in the Final Rule in redline/strikeout format, and further information regarding docketing of compliance filings and specific filing instructions, please visit our Web site at the following location *http://www.ferc.gov/industries/electric/indus-act/oatt-reform.asp.*

[111] These entities are not FPA public utilities and therefore are not subject to the Commission's jurisdiction under sections 205 and 206 of the FPA.

[112] *See* Order No. 888–A at 30,285–86.

[113] For non-public utilities that choose to use the safe harbor tariff, the Commission noted in the NOPR that the existing safe harbor provisions would need to be substantially conforming or superior to the new *pro forma* OATT. A non-public utility that already has a safe harbor tariff would therefore be required to amend its tariff so that its provisions substantially conform or are superior to the new *pro forma* OATT if it wishes to continue to qualify for safe harbor treatment. As the Commission stated in Order No. 888–A, a non-public utility may limit the use of its voluntarily offered safe harbor reciprocity tariff only to those transmission providers from whom the non-public utility obtains open access service, as long as the tariff otherwise substantially conforms to the *pro forma* OATT. *See* Order No. 888–A at 30,289.

[114] The Commission noted in the NOPR that LPPC has committed to voluntary compliance with a set of guidelines for the provision of comparable service under FPA section 211A.

from an unregulated transmitting utility that has not requested service under the public utility's OATT and the reciprocity obligation therefore does not apply. The Commission stated that such a customer may file an application with the Commission seeking an order compelling the unregulated transmitting utility to provide transmission service that meets the standards of FPA section 211A. The Commission further proposed to amend its regulations to make clear that an applicant in an FPA section 211A proceeding against a non-public utility that has submitted an acceptable safe harbor tariff has the burden of proof to show why service under the safe harbor tariff is not sufficient and why an FPA section 211A order should be granted. In addition, the Commission stated in the NOPR its expectation that unregulated transmission providers would participate in the proposed open and transparent regional planning processes and noted that, if there were complaints about such participation, they would also be addressed on a case-by-case basis.

167. The NOPR proposed to retain the existing reciprocity policy as applied to foreign utilities doing business in the United States, which we adopted pursuant to sections 205 and 206 of the FPA. By maintaining the same reciprocity requirement for these foreign utilities as for domestic, non-public utilities, the Commission stated that it would ensure that foreign entities will continue to be treated no less favorably than domestic, non-public utilities.

Comments

168. The majority of the commenters support the Commission's decisions to retain the reciprocity provision and to adopt a case-by-case approach to FPA section 211A.[115] These commenters reason that there is no evidence of a general problem of non-public utilities failing to provide transmission service and that, for the most part, non-public utilities already provide transmission on an as-available basis under comparable terms, regardless of whether a tariff is on file with the Commission. In addition, Santa Clara and TANC state that the Commission's proposal apparently respects the nonjurisdictional status of public power.

169. LPPC reiterates its prior offer of voluntary compliance with a set of guidelines for the provision of comparable open access service, which it contends will provide a significant degree of standardization for such service. Thus, LPPC believes that generic action under section 211A is not necessary. In addition, LPPC asserts that there is no evidence on record of undue discrimination by a nonjurisdictional entity that would justify the Commission reversing the NOPR decision to act on a case-by-case basis under FPA section 211A.[116]

170. On the other hand, several commenters urge the Commission to implement FPA section 211A on a generic basis.[117] AWEA argues that reciprocity tariffs do not subject the nonpublic utilities to Commission enforcement as would an OATT established under FPA section 211A. AWEA urges the Commission to proceed on a generic basis to ensure that nonjurisdictional utilities comply with the reformed OATT under exactly the same terms and conditions as jurisdictional utilities. On reply, however, APPA argues that the comparability standard does not mean that unregulated transmitting utilities must comply with the reformed OATT under exactly the same terms and conditions as jurisdictional entities.

171. In its reply comments, EEI states that, while LPPC's voluntary proposal is a step in the right direction, LPPC's proposal does not go far enough to assure that reciprocal transmission service is provided in a non-discriminatory manner. EEI asserts that LPPC's proposal still gives the individual non-public utility transmission provider the discretion to decide what is or is not comparable and not unduly discriminatory. Moreover, EEI notes, LPPC does not represent the universe of non-public utility transmission providers, rather only 24 of the largest governmentally-owned transmission providers.

172. Some commenters argue that the case-by-case approach proposed in the NOPR does not satisfy the Commission's stated goal of remedying undue discrimination and its intent to provide transparent, consistent and clear rules for use of the nation's transmission grid.[118] Calpine contends that the administrative burden of monitoring and administering customer complaints or processing applications that seek to compel unregulated transmitting utilities in different parts of the country to provide comparable service would create a ''patchwork of open and closed'' unregulated transmitting utilities, just like the patchwork of open and closed jurisdictional transmission systems the Commission sought to eliminate when it issued Order No. 888. Calpine also states that its comments on the NOI in this proceeding provide several examples of the kinds of problems it has experienced in seeking transmission service from unregulated transmitting utilities in a variety of regions and across multiple transmission systems.

173. California Commission argues that FPA section 211A gives the Commission the authority to require previously nonjurisdictional entities to file tariffs with the Commission that would be subject to the due process and the ''just and reasonable'' requirements of the FPA. California Commission urges the Commission to actively explore a set of mandatory actions that the Commission may impose on nonjurisdictional entities and states that, if the Commission is reluctant to do so in this proceeding, it should initiate a new rulemaking to consider such rules. California Commission asserts that there are a number of sound policy reasons for taking generic action to address the mandate of FPA section 211A. First, it argues that Commission action would prevent the balkanization of the grid that can result if a nonjurisdictional transmission owner refuses to participate in an RTO or ISO whose service area surrounds, encompasses, or overlaps it. Second, California Commission argues that Congress has given the Commission explicit authority to require previously nonjurisdictional entities to provide transmission service on a non-preferential and non-discriminatory basis. Finally, California Commission asserts, the Commission would be able to squarely address generic seams issues created by the existence of control areas operated by previously unregulated transmission owners and the ability of such entities to ''free ride'' on the systems and open access requirements of the jurisdictional entities.

174. In its reply comments, CMUA contests California Commission's assertion that those outside CAISO operations are ''free riders.'' CMUA notes that its members post their excess transmission capacity on wesTTrans (an OASIS site serving the Western Interconnection) thus making it available to third parties, and that its members outside the CAISO also pay a

[115] *E.g.,* APPA, Bonneville, LPPC, Newfoundland, NRECA, PGP, Sacramento, Salt River, Santa Clara, Santee Cooper, Seattle, TANC, TAPS, TVA, Tacoma, WAPA, CMUA Reply, East Texas Cooperatives Reply, Lassen Reply, and Public Power Council Reply.

[116] *See also* Public Power Council Reply and Sacramento Reply.

[117] *E.g.,* AWEA, California Commission, Calpine, EEI, MidAmerican, San Diego G&E, and Xcel.

[118] *E.g.,* Calpine, MidAmerican, and Xcel.

host of CAISO fees.[119] CMUA states that it does not contest that there are ''seams'' between organized markets and neighbors, but it asserts that this docket is not the place for this discussion and FPA section 211A is not the remedy. In its reply comments, APPA also urges the Commission to reject California Commission's proposal. APPA argues that section 211A was not intended, nor could the Commission use it, to require nonjurisdictional transmission providers to participate in an RTO and, therefore, California Commission's proposal exceeds the Commission's authority under section 211A.[120]

175. EPSA, in its reply comments, disagrees with commenters who appear to believe that nonjurisdictional transmitting utilities will not have to take any steps to comply with a final order in this rulemaking. EPSA states that its understanding is that the Commission's principle of reciprocity would apply to any changes in the *pro forma* OATT adopted in the Final Rule. Accordingly, both jurisdictional and nonjurisdictional transmitting utilities that adopted the Order No. 888 *pro forma* OATT would have to make compliance filings. In addition, EPSA argues that nonjurisdictional transmitting utilities that previously received an Order No. 888 waiver or that wish to request such a waiver should have an affirmative duty to file a request for a waiver. In the event that a nonjurisdictional entity wishes to file a bilateral contract, EPSA contends that it should be required to file a ''reciprocity'' contract pursuant to FPA section 205. If a nonjurisdictional transmitting utility does not adopt a revised *pro forma* OATT as a ''safe harbor,'' EPSA argues the Commission's standard of review should be whether the nonjurisdictional transmitting utility's alternative tariff is ''equal or superior to'' a revised *pro forma* OATT.

176. EPSA, in its reply comments, supports implementing the rate provisions of FPA section 211A in a proceeding separate from this particular proceeding. EPSA states that such a proceeding could take a generic approach, in that nonjurisdictional transmitting utilities could be required to set transmission rates for third-party transmission services that are computed using rate determinants that are comparable to the determinants that the non-public utility uses to calculate transmission rates for its native load.

177. With regard to specific reciprocity obligations, LPPC argues that the Commission should revise section 6 of the *pro forma* OATT to reflect the comparability standards now contained in FPA section 211A. LPPC states that, with the implementation of FPA section 211A, it is appropriate to revise the *pro forma* OATT language in order to reflect the unregulated utility's obligation ''to provide transmission service comparable to the service the customer provides itself'' as the ''quid pro quo'' for receiving reciprocal service. LPPC also argues that, with respect to the existing safe harbor option, the Commission should revise its test for evaluating a safe harbor OATT from one which asks whether the proposal is equivalent or superior to the *pro forma* OATT, to one which asks whether the service provided under the proposed OATT is comparable to the service that the unregulated utility provides itself.

178. EPSA replies that LPPC's suggestion to revise the language of section 6 ironically would require nonjurisdictional transmitting utilities to offer third party customers transmission services that are comparable to network transmission service, which is a higher quality of transmission service than the revised OATT and which is unlikely to be supported by nonjurisdictional transmitting utilities. EPSA states that it believes that FPA section 211A requires a nonjurisdictional transmitting utility to provide transmission service (at its interfaces with jurisdictional public utilities and internal sources) that is comparable to the service it is taking at interfaces or internal sources. EPSA therefore argues that the appropriate standard for determining whether a nonjurisdictional transmitting utility's tariff is comparable is whether the nonjurisdictional utility's tariff is ''equal or superior'' to the revised *pro forma* OATT.

179. LPPC also argues that the two categorical exemptions from FPA section 211A articulated in FPA section 211A(c)(3) (based on size and the value of the unregulated system to the integrated grid) should not be exclusive. Rather, LPPC contends that the two exemptions should guide the Commission in considering similar requests for exemption. For example, LPPC argues that relatively small utilities, which nevertheless exceed an express threshold, should be permitted to demonstrate that their systems are simply too small, and that their facilities are not sufficiently strategic, to call for full inclusion in the FPA section 211A regime. Similarly, LPPC states that, in certain public systems, only some discrete portions of the system would fairly be considered part of the integrated system. In these cases as well, LPPC argues, it would make sense for the Commission to entertain requests for partial waiver.

180. If the Commission does not reconsider its proposal not to act generically under FPA section 211A, EEI contends that there are other actions the Commission should take. In order to facilitate full compliance with the reciprocity obligation, EEI urges the Commission at least to clarify and strengthen the obligations of non-public utility transmission providers under the reciprocity provision,[121] exercise oversight and monitor their compliance with the reciprocity obligation, and require them to provide greater transparency of the transmission services and the terms and conditions of service they offer so that those seeking transmission service under the reciprocity provision are able to determine whether they are complying with their reciprocity obligation.

181. With respect to the reciprocity provision in the *pro forma* OATT, EEI requests that the Commission update it by including reference to transmission service by ISOs and RTOs. EEI asks that the reciprocity provision be modified to provide that, if an ISO or RTO is the transmission provider, the reciprocity obligation is owed to all members of the ISO or RTO. EEI notes, however, that even this action would not require non-public utility transmission providers to provide transmission services to other entities who are eligible customers under the ISO or RTO OATT and who are not transmission providers, such as independent generators. EEI asserts that non-public utility transmission providers may discriminate against certain transmission customers unless the reciprocity obligation is expanded. Sempra Global also asks the Commission to clarify that the right to seek transmission service from an unregulated transmitting utility pursuant to FPA section 211A is available to any entity that qualifies as an eligible customer under the Commission's *pro forma* OATT.

182. EEI acknowledges that the Commission declined in Order No. 888–A to expand the reciprocity provision beyond the specific transmission provider from which the transmission customer takes service on the ground that requiring ''non-public utilities to offer transmission service to entities other than public utility transmission providers increases the chances that they could lose tax-exempt status.'' [122] However, EEI states, in 2002, the

[119] *See also* APPA Reply.

[120] *See also* CMUA Reply and Santa Clara Reply.

[121] Xcel and MidAmerican support EEI's proposal on this issue.

[122] *Citing* Order No. 888–A at 30,287.

Department of the Treasury adopted final regulations that in effect provide that providing open access transmission does not constitute private use.[123] Therefore, EEI argues, this reason for limiting the services provided under the reciprocity obligation is no longer applicable.[124]

183. Moreover, EEI argues, as originally established in Order Nos. 888 and 888–A, the Commission stated that it was ''conditioning the use of public utility open access tariffs, by all customers including non-public utilities, on an agreement to offer comparable (not unduly discriminatory services) in return.'' [125] However, EEI states, the reciprocity provision of the *pro forma* OATT refers to ''similar terms and conditions'' but does not make clear what they should be ''similar'' to. EEI argues that the term ''similar'' does not necessarily encompass the requirement that is part of comparability that the services provided be ''not unduly discriminatory'' as Order Nos. 888 and 888–A require. EEI proposes that the *pro forma* OATT be amended to refer to ''comparable terms and conditions'' rather than ''similar'' to align it with Order Nos. 888 and 888–A. Finally, EEI also states that the Commission should also reaffirm that the reciprocity obligation is binding on Canadian utilities.

184. On reply, APPA urges the Commission to reject EEI's proposed expansion of the reciprocity provision. APPA notes that EEI's proposed application of the reforms to all non-public utility transmission providers would potentially include a broader universe of public power entities than those subject to FPA section 211A. Moreover, APPA argues, many of the goals that EEI claims it wishes to accomplish would be accomplished even if the Commission takes no action.

185. In its reply comments, the Canadian Electricity Association urges the Commission to reject EEI's proposal to strengthen the reciprocity obligation so as to require the offering of transmission service to all eligible customers. The Canadian Electricity Association argues that the effect of EEI's proposal would be to enable a generator generating power in Canada to obtain access on a Canadian utility's transmission system, which is not the situation under the current reciprocity requirement. Consequently, the Canadian Electricity Association asserts, EEI's proposal would allow the Commission to fully impose open access requirements in Canada and would violate the principles of comity and undermine Canadian jurisdictional sovereignty.

186. The Canadian Electricity Association also repeats its earlier arguments made in response to the NOI that, to the extent the Commission adopts the comparability standard in FPA section 211A for non-public utilities, the Commission must apply the same changes to Canadian utilities.

187. EEI also urges the Commission to take certain steps to increase transparency and accountability in complying with the reciprocity requirement.[126] For example, EEI states, the Commission could include on its Web site a list of all non-public utility transmission providers that have Commission-approved safe harbor reciprocity tariffs. According to EEI, such a list of entities would facilitate use of their transmission systems, provide transparency, and provide recognition to these entities for their voluntary efforts in accomplishing these goals.[127]

188. EEI requests that the Commission also establish minimal transparency requirements for non-public utility transmission providers.[128] EEI asserts that the Commission has ample authority under FPA section 211A and under the reciprocity provision of the *pro forma* tariff to apply this information reporting requirement to those large non-public utility transmission providers that are not exempted by section 211A(c).[129]

189. On reply, several commenters oppose EEI's transparency proposal. Among other things, they argue that EEI's proposal is unnecessary and duplicative of information that is already publicly available—*e.g.*, the non-public utility's Web site, the Commission's Web site, or in some instances a regional entity's Web site (such as the wesTTrans OASIS).[130] APPA further notes that LPPC has proposed that the terms and conditions in non-public utility transmission provider's tariffs would be publicly available on the individual utility's or a regional entity's Web site. In addition, NRECA asserts that, absent waivers, any non-public utility transmission provider that has adopted a ''safe-harbor'' tariff has adopted all of the OATT, OASIS, and Standards of Conduct requirements that apply to public utilities. NRECA and TANC both assert that the Commission does not have similar informational filing requirements for public utilities. Furthermore, TANC argues that it would be a waste of Commission resources to compile a list of all non-public utility transmission providers that have Commission-approved safe harbor tariffs. TANC also argues that to provide such an information filing would be unduly burdensome and a waste of nonjurisdictional utility transmission provider time and limited resources.

Commission Determination

190. The Commission retains the reciprocity language in the Order No. 888 *pro forma* OATT, but updates it to include references to ISOs and RTOs, as suggested by EEI. We also modify the reciprocity provision to provide that, if an ISO or RTO is the transmission provider, the reciprocity obligation is owed to all members of that ISO or RTO. We concur with EEI's assessment that such modifications will more accurately reflect the current state of the industry. However, we will not adopt EEI's proposal to extend the reciprocity obligation to all eligible customers or

[123] Treas. Reg. § 1.141–7(g).

[124] EEI asserts that the Commission also has the authority to make this change under FPA section 211A, which provides that the Commission may not require a State or municipality to take action under that section that would violate a private utility bond rule. If a non-public utility transmission provider is concerned about the impact on the tax-exempt status of its bonds, EEI suggests that it could seek a waiver from the Commission.

[125] *Citing* Order No. 888–A at 30,285.

[126] According to EEI, the new authority granted to the Commission under EPAct 2005 section 1281 (new FPA section 220) (Electricity Market Transparency Rules), which applies to all ''market participants,'' provides another basis for requiring greater transparency under the *pro forma* OATT by non-public utility transmission providers. EEI argues that the Commission could rely on this new authority to require greater transparency in transmission service provided under the reciprocity obligation.

[127] EEI notes that, in the NOPR, the Commission referenced voluntary guidelines being developed by members of the LPPC. EEI believes this is a step in the right direction and looks forward to the opportunity to provide input on the proposed guidelines. In EEI's view, however, if any LPPC member wishes to use these guidelines as a safe harbor tariff, it must meet the safe harbor standard that the terms of service must be ''substantially conforming or superior to'' the revised OATT. The reciprocity obligation requires that the terms and conditions of service be comparable to those that the non-public utility transmission provider applies to itself and not be unduly discriminatory.

[128] EEI states that this informational filing should include information such as: whether or not they have a reciprocity or other tariff and how it can be obtained, whether they have an OASIS and location URL, whether they have standards of conduct and where they are posted, whether they have posted business practices, their contact for regional transmission planning, and their ATC methodology.

[129] Section 211A authorizes the Commission to require certain unregulated transmitting utilities to provide transmission services at rates that are comparable to those that the unregulated transmitting utilities charges itself and on terms and conditions (not related to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential.

[130] *E.g.*, APPA Reply, CMUA Reply, LPPC Reply, Lassen Reply, NRECA Reply, Sacramento Reply, and TANC Reply.

LPPC's proposal to revise the *pro forma* OATT language regarding comparability. We are not persuaded that either proposal is necessary at this time to prevent undue discrimination absent a complaint.

191. We will also retain Order No. 888's three alternative provisions for satisfying the reciprocity condition, *i.e.:* A non-public utility that owns, controls, or operates transmission and seeks transmission service from a public utility must either satisfy its reciprocity obligation under a bilateral agreement, seek a waiver of the OATT reciprocity condition from the public utility, or file a safe harbor tariff with the Commission. Thus, for non-public utilities that choose to use the safe harbor tariff, its provisions must be substantially conforming or superior to the revised *pro forma* OATT in this Final Rule. A non-public utility that already has a safe harbor tariff must amend its tariff so that its provisions substantially conform or are superior to the revised *pro forma* OATT if it wishes to continue to qualify for safe harbor treatment. As the Commission stated in Order No. 888–A, a non-public utility may limit the use of its voluntarily offered safe harbor reciprocity tariff only to those transmission providers from whom the non-public utility obtains open access service, as long as the tariff otherwise substantially conforms to the *pro forma* OATT.[131] We reiterate that these reciprocity requirements apply equally to all non-public utility transmission providers, including those located in foreign countries.

192. As the Commission proposed in the NOPR, we will not adopt a generic rule to implement the new FPA section 211A. Rather, we will apply its provisions on a case-by-case basis, such as when a public utility seeks service from an unregulated transmitting utility that has not requested service under the public utility's OATT and the reciprocity obligation therefore does not apply. A potential customer may file an application with the Commission seeking an order compelling the unregulated transmitting utility to provide transmission service that meets the standards of FPA section 211A. We adopt the NOPR proposal to amend our regulations to make clear that an applicant in an FPA section 211A proceeding against a non-public utility that has submitted an acceptable safe harbor tariff shall have the burden of proof to show why service under the safe harbor tariff is not sufficient and why an FPA section 211A order should be granted.[132] Further, as we indicate below, we restate our expectation that unregulated transmission providers will participate in the open and transparent regional planning processes ordered below and note that, if there are complaints about such participation or the lack thereof, we will address them on a case-by-case basis.

V. Reforms of the OATT

A. Consistency and Transparency of ATC Calculations

193. In the NOPR, the Commission proposed to take action under FPA section 206 to remedy undue discrimination in the provision of transmission service. The Commission recognized that while Order Nos. 888 and 889 require transmission providers to offer and post any available transfer capability (ATC) on their OASIS, and file the methodology they use to calculate ATC as Attachment C to their OATTs, the industry has not developed a consistent methodology for evaluating ATC nor have transmission providers adequately made their ATC calculation methodology transparent. This inconsistency and lack of transparency creates the potential for undue discrimination in the provision of open access transmission service.

194. In the NOPR, the Commission proposed to address this potential for undue discrimination by requiring industry-wide consistency and transparency of all components of the ATC calculation methodology and certain definitions, data, and modeling assumptions. The Commission proposed to provide guidance regarding aspects of ATC calculations that should be more consistent and proposed to direct public utilities, working through NERC[133] and NAESB, to revise reliability standards and business practices that are relevant to ATC calculations. The Commission also proposed to require increased detail in Attachment C of each transmission provider's OATT and proposed amending the OASIS regulations to require increased transparency. Although commenters challenged aspects of this proposed remedy, no commenters challenged the underlying finding that ATC reform is necessary to remedy undue discrimination in the provision of transmission service.

195. The Commission also indicated that the lack of consistent, industry-wide ATC calculation standards poses a threat to the reliable operation of the bulk-power system, particularly because a transmission provider may not know of its neighbors' system conditions affecting its own ATC values. As a result of this reliability impact, the Commission observed that the proposed ATC reforms are also supported by FPA section 215(d)(5), through which the Commission has the authority to direct the ERO to submit a reliability standard that the Commission considers appropriate to implement FPA section 215.

196. In light of these concerns, we direct public utilities, working through NERC reliability standards and NAESB business practices development processes, to produce workable solutions to complex and contentious issues surrounding improving the consistency and transparency of ATC calculations. We are directing our guidance to public utilities and require that they implement our direction by working with NERC to develop reliability standards that accomplish the ATC reforms required in this rulemaking. We will coordinate our directives here with the ATC-related reliability standards that are pending in Docket No. RM06–16–000.[134] The specifics of our findings with respect to ATC reform are discussed below.

1. Consistency

197. In order to address the potential for remaining undue discrimination in the determination of ATC, the Commission proposed to require industry-wide consistency of certain definitions, data, and modeling assumptions of the ATC calculation.

a. Necessary Degree of Consistency

NOPR Proposal

198. In the NOPR, the Commission recognized that transmission providers use several basic types of ATC calculation methodologies (with various permutations), and did not propose to require a single ATC calculation methodology to be applied by all transmission providers. However, the Commission proposed to achieve greater consistency in ATC calculations by directing the development of consistent definitions of the ATC components,[135] as well as consistent data inputs, modeling assumptions, and data

[131] *See* Order No. 888–A at 30,289.

[132] *See* revised 18 CFR 35.28(e)(1)(ii).

[133] All references to NERC in the context of developing reliability standards are to NERC as the Electric Reliability Organization (ERO).

[134] We note that many of the ATC-related reliability standards filed in Docket No. RM06–16–000 were not addressed by the NOPR in that proceeding, pending the submittal of additional information. *See Mandatory Reliability Standards for the Bulk-Power System*, 71 FR 64770 (Nov. 3, 2006), FERC Stats. & Regs. ¶ 32,608 at Appendix A (2006) (Reliability Standards NOPR).

[135] The ATC components are total transfer capability (TTC), existing transmission commitments (ETC), capacity benefit margin (CBM), and transmission reserve margin (TRM).

exchange and coordination protocols. The Commission also required each transmission provider using an Available Flowgate Capacity (AFC) methodology to explain its definition of AFC, its calculation methodology and assumptions, and its process for converting AFC into ATC.

Comments

199. While the majority of commenters[136] support the NOPR's proposal to increase consistency in the calculation of ATC, several caution the Commission to allow flexibility[137] in order to capture differences in system operations,[138] usage, market operations,[139] and topology. Many assert that industry-wide standardization of the ATC calculation might not be possible and suggest that the Commission consider interconnection-wide,[140] regional,[141] or even sub-regional standardization. NARUC urges the Commission to facilitate State commission participation in efforts to reform ATC methodologies and calculations on a regional or sub-regional basis. Conversely, several commenters suggest that, if the Commission considers allowing use of different ATC calculations, it must impose a heavy burden on any entity seeking to justify a departure from the interconnection-wide or regional ATC standard.[142]

200. Constellation proposes that the Final Rule establish a rebuttable presumption that the basic ATC calculation formula[143] set forth in NERC's current ATC definition be identical within a region and that each element of the calculation have the same meaning for all transmission providers. Williams requests on reply that the Commission establish an industry-wide standard for the calculation of ATC and emphasizes that a consistent and transparent approach to evaluating ATC and ATC/AFC modeling assumptions is a prerequisite to the elimination of the broad discretion afforded transmission providers and, with it, the subtle discrimination practiced against customers.

201. Southern suggests that the basic ATC calculation should be defined for both firm and non-firm ATC calculations and also proposes that the following basic formulas be used: ATC (firm) = TTC − Firm Commitments or ETC − TRM − CBM; and ATC (non-firm) = TTC − Firm and Nonfirm Commitments + Postbacks of Redirected and Unscheduled Service − TRM − CBM. In addition, TDU Systems requests that the Commission require standardization of methods for calculating AFC and require NERC to create a formal definition of AFC.

202. PNM–TNMP and Bonneville express concerns with imposing an industry-wide standardized ATC methodology, arguing that there are too many variables in the way systems are operated. In its reply comments, PNM–TNMP adds that NERC's ATC calculation method should take into consideration the need for regional variation, and focus on consistency in definitions and data inputs. WestConnect participants caution that the replacement of the contract path ATC approach used in the Western Electricity Coordinating Council (WECC) with a flowgate methodology could seriously disrupt transmission service in the Western Interconnection.

203. PGP states that, although regional and sub-regional consistency is a good idea, there is no need for the Commission to require ''consistent'' ATC methodologies; rather, the emphasis should be on transparency of the methodologies, inputs, calculations and outputs. Other commenters agree that the Commission should not require overall standardization of ATC calculations, but instead permit regional differences with respect to certain aspects of the calculation of ATC.[144] EEI argues that standardization of ATC methodologies would require transmission systems to adopt a ''lowest common denominator'' standard in order to ensure that system reliability is not compromised, which would result in a reduction in ATC. EEI suggests that the Commission should direct NERC to develop ATC calculation standards that incorporate regional variations in order to maximize confidence in standards and system use, and maintain reliability. In its reply comments, Exelon disagrees with EEI and states that there are no regional differences within the individual interconnections that would justify differences in the application of ATC calculations.

204. Exelon states that ATC definitions must be consistent so that the various ATC components such as TRM have the identical meaning for all industry participants. In addition, Exelon argues that each ATC component (ETC, TRM, and CBM) must be used in the same manner for all purposes (*e.g.*, granting transmission service to third parties or for the transmission provider's own network load).

205. At the October 12 Technical Conference, NERC recognized that the goal of achieving consistency may not mean that a single ATC methodology is required.[145] NERC explained that consistency can be achieved with a limited number of methodologies if the requirements of those methodologies are properly coordinated and communicated. NERC stated that the Standard Drafting Team modifying the modeling, data, and analysis (MOD) standards[146] relevant to ATC is developing a standard applicable to three ATC calculation methodologies: the rated system path methodology (contract path), the network response methodology (network ATC), and the network response flowgate methodology (network AFC). NERC and the other panelists agreed that the two network methodologies are very similar in technique. NERC argued that the ultimate goal of ATC-related reforms should be to standardize definitions. The entire panel agreed that definitions must be consistent and a panelist representing Constellation asserted that broad differences in the core definitions of the ATC calculation are neither rational nor explainable.[147]

206. New Mexico Attorney General recommends that the Commission allow a utility to waive the requirement to make certain elements of ATC more consistent if the utility can show that it is making adequate progress towards developing consistent and transparent ATC calculations at the sub-regional level.

Commission Determination

207. The Commission adopts the NOPR proposal to require industry-wide

[136] E.g., Alcoa, Alliance, Ameren, Arkansas Commission, Arkansas Municipal, AWEA, Duke, E.ON, EEI, ELCON, EPSA, Exelon, LDWP, MidAmerican, NRECA, NPPD, NERC, Occidental, Powerex, PJM, PPL, Progress Energy, Project for Sustainable FERC Energy Policy, Santee Cooper, Southern, Suez Energy NA, SPP, TAPS, TVA, TDU Systems, TranServ, Tacoma, TANC, WECC, WestConnect, and Xcel.

[137] *E.g.* Allegheny, Entergy, Indianapolis Power, North Carolina Agencies, and NARUC.

[138] *E.g.* Bonneville, Northwest IOUs, and NorthWestern.

[139] *E.g.* CAISO.

[140] *E.g.* Ameren and Tacoma.

[141] *E.g.* APPA, Barrick Reply, Duke, EEI, Imperial, International Transmission, LDWP, NARUC, Nevada Companies, New York Commission, NRECA, MidAmerican, Occidental Reply, Pinnacle, PNM-TNMP, Public Power Council, CREPC, Salt River, Seattle, South Carolina E&G Reply, SPP Reply, Utah Municipals, and WPS Companies Reply.

[142] *E.g.* TDU Systems and East Texas Cooperatives Reply.

[143] *E.g.*, ATC = TTC − (ETC + CBM + TRM).

[144] *E.g.,* EEI Reply, NARUC Reply, and Powerex Reply.

[145] Transcript of October 12 Technical Conference at 125–150.

[146] MOD standards refers to Modeling, Data, and Analysis Reliability Standards.

[147] Transcript of October 12 Technical Conference at 149–160.

consistency of all ATC components and certain definitions, data, and modeling assumptions. The Commission also will require each transmission provider to include in Attachment C to its OATT detailed descriptions for calculating both firm and non-firm ATC, consistent with the requirements of this Final Rule. The purpose of increasing the consistency and transparency of ATC calculations is to reduce the potential for undue discrimination in the provision of transmission service, specifically by reducing the opportunity for transmission providers to exercise excessive discretion. We find that the amount of discretion in the existing ATC calculation methodologies gives transmission providers the ability and opportunity to unduly discriminate against third parties. In order to minimize this discretion, the Final Rule requires that all ATC components (*i.e.*, TTC, ETC, CBM, and TRM) and certain data inputs, data exchange, and assumptions be consistent and that the number of industry-wide ATC calculation formulas be few in number, transparent and produce equivalent results. The Commission finds that these reforms will facilitate development of a more coherent and uniform determination of ATC.

208. We reject requests to establish a single methodology for calculating ATC, however, for several reasons. It is not our intent to require transmission providers to incur the expense of developing and adopting a new one-size-fits-all software package to calculate ATC. We also see little benefit in requiring a ''lowest common denominator'' ATC calculator. While a uniform methodology may result in all transmission providers calculating ATC in an identical manner, it would also likely lead to software implementation costs in excess of the resulting benefits. More importantly, we find that the potential for discrimination does not lie primarily in the choice of an ATC calculation methodology, but rather in the consistent application of its components.

209. All ATC calculation methodologies derive ATC by modeling the system to establish TTC, expressed in terms of contract paths or flowgates, and reducing that figure by existing transmission commitments (*i.e.*, ETC), a margin that recognizes uncertainties with transfer capability (*i.e.*, TRM), and a margin that allows for meeting generation reliability criteria (*i.e.*, CBM). These calculation methodologies are developed based on physical characteristics of the transmission provider's transmission system, historical modeling practices, and processes developed for collection of input data related to transmission provider's own system conditions as well as relevant data that model neighboring systems' conditions. We therefore find that it is not the methodologies for calculating ATC themselves that create the opportunity for undue discrimination. Instead, we find that the potential for undue discrimination stems from two main sources:

(1) Variability in the calculation of the components that are used to determine ATC and (2) the lack of a detailed description of the ATC calculation methodology and the underlying assumptions used by the transmission provider.[148] The combination of a lack of consistency of the components of the ATC calculation coupled with the lack of transparency leaves customers and regulators unable to verify ATC calculations and may allow transmission providers to calculate ATC in different ways for different customers.

210. Accordingly, we conclude that industry-wide consistency of all ATC components (TTC, ETC, CBM, and TRM) and certain data inputs and exchange, modeling assumptions, calculation frequency, and coordination of data relevant for the calculation of ATC will reduce the opportunities for the exercise of discretion that may lead to undue discrimination against unaffiliated transmission customers. The Commission understands that NERC currently is developing standards for three ATC calculation methodologies (contract or rating path ATC, network ATC, and network AFC).[149] If all of the ATC components and certain data inputs and assumptions are consistent, the three ATC calculation methodologies being finalized by NERC through the reliability standards development process will produce predictable and sufficiently accurate, consistent, equivalent, and replicable results. It is therefore not necessary to require a single industry-wide ATC calculation methodology. The Commission instead concludes that use of the ATC calculation methodologies included in reliability standards currently being developed by NERC is acceptable.

211. As TDU Systems note, there is neither a definition of AFC in NERC's Glossary nor an existing reliability standard that discusses the AFC method. In order to achieve consistency in each component of the ATC calculation (discussed below), we direct public utilities, working through NERC, to develop an AFC definition and requirements used to identify a particular set of transmission facilities as a flowgate. However, we remind transmission providers that our regulations require the posting of ATC values associated with a particular path, not AFC values associated with a flowgate. Transmission providers using an AFC methodology must therefore convert flowgate (AFC) values into path (ATC) values for OASIS posting. In order to have consistent posting of the ATC, TTC, CBM, and TRM values on OASIS, we direct public utilities, working through NERC, to develop in the MOD–001 standard a rule to convert AFC into ATC values to be used by transmission providers that currently use the flowgate methodology.

212. The Commission also believes that further clarification is necessary regarding the calculation algorithms for firm and non-firm ATC.[150] Currently, NERC has no standards for calculating non-firm ATC. We find that the same potential for discrimination exists for non-firm transmission service as for firm service and that greater uniformity in both firm and non-firm ATC calculations will substantially reduce the remaining potential for undue discrimination. Therefore, we direct public utilities, working through NERC, to modify related ATC standards by implementing the following principles for firm and non-firm ATC calculations: (1) For firm ATC calculations, the transmission provider shall account only for firm commitments; and (2) for non-firm ATC calculations, the

[148] For example, utilities A and B would agree that ATC is derived by reducing TTC by the sum of ETC, CBM and TRM, but utility A may define ETC to include set-asides for contingencies while utility B may not.

[149] *See Transcript of October 12, 2006 Technical conference at 125.* Thee three methodologies are different computational processes to determine a transmission system's ATC. The first, contract path, examines TTC for every A-to-B path on the system in concert with all others, reduces ATC by path for ETC, TRM, and CBM, as appropriate, and produces ATC for each path. The second method, net work ATC, uses a simulator to look not at each path, but each transmission element (line, substation, *etc.*,), and rule first contingency simulations to establish ATC on a network basis. The third method, network AFC, uses a simulator to examine critical flowgates over a wider area, then requires a second step to convert AFC values to particular path ATC values.

[150] The NERC ATC definition does not differentiate firm and non-firm ATC from a high level generic ATC definition: ''A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin.'' *See* North American Electric Reliability Corporation, *Glossary of Terms Used in Reliability Standards* (February 7, 2006).

transmission provider shall account for both firm and non-firm commitments, postbacks of redirected services, unscheduled service, and counterflows. We understand that these principles are currently followed by most transmission providers and believe they should be clearly set forth in the ATC-related reliability standards. As described below, each transmission provider's Attachment C must include a detailed formula for both firm and non-firm ATC, consistent with the modified ATC-related reliability standards.

213. We deny New Mexico Attorney General's request to grant waiver of the ATC consistency requirements to utilities that can show that they are making adequate progress toward developing consistent and transparent ATC calculations at the sub-regional level. While we certainly encourage regional consistency with respect to the ATC calculation methodology, we are not requiring consistency; therefore a waiver is not necessary. As discussed in more detail below, any request for waiver from these ATC calculation requirements must take place through the NERC reliability standards development process as a request for a regional difference, since the ATC requirements will be determined through the NERC reliability standards.

b. Process To Achieve Consistency

NOPR Proposal

214. In the NOPR, the Commission expressed confidence that the existing NERC and NAESB processes were well-suited to achieving greater consistency in ATC calculations. The Commission therefore proposed to require public utilities, working through NERC and NAESB, to revise the reliability standards and business practices relating to ATC, consistent with the guidance provided in the Final Rule, within 180 days after the publication of the Final Rule in the **Federal Register**.

Comments

215. Many commenters support the Commission's proposal directing NERC and NAESB to develop reliability standards and business practices addressing ATC.[151] In addition, several commenters urge the Commission to be more precise in differentiating between policy and business standards, and urge the Commission to provide more guidance to NERC and/or NAESB.[152] NRECA suggests that the Commission require NERC and NAESB to file the results of their processes with the Commission, give all interested parties an opportunity to comment on the proposals, and exercise its independent authority to review, and if necessary, remand the issues or proposals back to NERC and NAESB.

216. Occidental states on reply that it does not oppose NERC having a role in developing the basic requirements and standards for ATC. However, Occidental also urges the Commission to adopt a process similar to that employed in developing the Standards for Business Practices and Communication Protocols for Public Utilities, which were incorporated by reference into the *pro forma* OATT.[153] There, the Commission allowed NAESB's Wholesale Electric Quadrant to develop, with widespread industry input, business practice standards that the Commission then reviewed, adopted and required public utilities to include in their OATTs by reference.[154] Occidental claims that this process would ensure industry input in the development of the methodology for ATC calculations, as well as Commission review and approval of the methodology.

217. Several commenters raise concerns that six months may not be sufficient time to develop ATC-related reliability standards and business practices.[155] Exelon, MidAmerican and NARUC propose that the Commission grant NERC one year from the date of the Final Rule to develop the necessary reliability standards. NARUC agrees with one year, but requests flexibility to assure that the NERC and NAESB processes can be adequately completed. NERC also states that it expects the standards development process, already underway, to be finalized with standards submitted to the Commission prior to the summer of 2007. LPPC recommends that, within six months of the issuance of the Final Rule, NERC be required to submit a progress report addressing the status and a work plan for conclusion within the ensuing six months. NRECA proposes that the Commission closely monitor the NERC and NAESB process. Some commenters strongly oppose a flexible deadline, and urge the Commission to establish a firm deadline that must be met.[156]

218. At the October 12 Technical Conference, NERC informed participants that a great deal of progress has been made since the proposed standards developed by the NERC Standard Committee in February 2006 were generated to address the recommendations made by the Long-Term AFC/ATC Task Force.[157] However, NERC indicates that a significant amount of work remains before the standard revisions are considered complete. Since NERC would like to finalize its revised standards for submittal to the Commission for the summer of 2007, NERC has established an aggressive schedule of meetings for drafting which will be coordinated with NAESB.

219. PJM outlines several guidelines it suggests the Commission should give to NERC and NAESB regarding the standards development process and recommends that Commission staff participate in the standards development process. Williams and EPSA likewise request that the Commission provide clear guidance to NAESB to assure efficiency and timeliness of the process.

220. Some commenters prefer engagement of a fully independent organization to develop standards and practices related to ATC.[158] EPSA strongly urges the Commission to require all transmission providers outside of RTO areas to contract with an independent entity to develop and/or monitor ATC calculations. Although TDU Systems agree with EPSA that vertically-integrated transmission providers that are not subject to the independent oversight of an ISO/RTO retain inherent incentives to discriminate against competitors, they contend that the benefit of independent oversight of ATC calculations must be weighed against the cost of that oversight. Alcoa suggests engaging the Institute of Electrical and Electronics Engineers (IEEE) instead of the Commission's proposal to use NERC and NAESB. APPA opposes that position. New York Commission proposes that regional reliability organizations, rather than NERC, complete this task and that the ATC calculators be closely coordinated by

[151] *E.g.*, Allegheny, APPA, Arkansas Commission, Bonneville, CAISO, Constellation, E.ON, EEI, ELCON, Entergy, Exelon, FirstEnergy, LPPC, MidAmerican, New York Commission, NERC, Northeast Utilities, Project for Sustainable FERC Energy Policy, PNM–TNMP, Santa Clara, Southern, Tacoma, TransServ, and Utah Municipals.

[152] *E.g.*, EPSA and Williams.

[153] *Citing Standards for Business Practices and Communication Protocols for Pub. Utils.*, Order No. 676, 71 FR 26199 (May 4, 2006), FERC Stats. & Regs. ¶ 31,216 (2006), *order on reh'g*, Order No. 676–A, 116 FERC ¶ 61,255 (2006).

[154] *Citing id.* at P 20.

[155] *E.g.*, Constellation, Duke, EEI, Exelon, LPPC, MidAmerican, NARUC, Northwest IOUs, Public Power Council, CREPC, Southern, TDU Systems, and WestConnect.

[156] *E.g.*, Utah Municipals and Entegra.

[157] *Citing* Long-Term AFC/ATC Task Force Final Report (Revised April 14, 2005), *available at http://www.nerc.com/~filez/ltatf.html.*

[158] *E.g.*, Alcoa, Fayetteville, and MISO.

ISOs and RTOs.[159] PJM contends on reply that New York Commission's proposal for coordination of ATC between ISOs and RTOs has been fulfilled at least between PJM and its neighbors, arguing that New York Commission's proposal is unnecessary and would add a layer of bureaucracy and cost. TAPS expresses concern with the Commission proposal to use NERC and encourages the Commission to be precise in its direction to NERC to accomplish the needed objective.

Commission Determination

221. The Commission directs public utilities, working through NERC and NAESB, to modify the ATC-related reliability standards and business practices in accordance with specific direction provided in this Final Rule. As we explain above, the development of a more coherent and uniform determination of ATC across a region will help limit the potential for undue discrimination in the calculation of ATC. The Commission concludes that the NERC reliability standards development process and the NAESB business practices development process are the appropriate forums for developing this consistency.

222. NERC has been certified as the ERO and, as such, has been found to have the ability to develop reliability standards through processes with reasonable notice and opportunity for public comment. NERC's processes are open and provide due process as well as a balance of interests, while assuring independence from users and owners and operators of the bulk-power system. Moreover, NAESB has a long history of developing standard business practices for the electric industry, on which the Commission has relied in various contexts. While other entities may bring certain benefits, commenters have not demonstrated the superiority of IEEE, a regional reliability organization, or a particular RTO over NERC and NAESB. Once components of ATC are made consistent and ATC calculation methodologies are made transparent, opportunities for discretion that may lead to undue discrimination in the calculation of ATC will be sufficiently eliminated to invalidate the need for the creation of independent entities to oversee that calculation. To the extent that, even following the adoption of these reforms, customers have complaints regarding the calculations performed by individual transmission owners, they can be addressed on a case-by-case basis.

223. With respect to a timeline for completion, the Commission concurs with NERC that a significant amount of work remains to be done on ATC-related reliability standards development. We also agree with the many commenters who state that the NOPR's proposed six-month timeline is too short for such a complex assignment. Although NERC projects that it may be able to complete the process by the summer of 2007 (which is approximately six months from the date of the Final Rule), we believe NERC should have additional flexibility with respect to its timeline. Accordingly, we direct public utilities, working through NERC, to modify the ATC-related reliability standards within 270 days after the publication of the Final Rule in the **Federal Register**. We also direct public utilities to work through NAESB to develop business practices that complement NERC's new reliability standards within 360 days after the publication of the Final Rule in the **Federal Register**. Finally, we direct NERC and NAESB to file, within 90 days of publication of the Final Rule in the **Federal Register**, a joint status report on standards and business practices development and a work plan for completion of this task within the timeframe established above.[160]

c. Applicability to ISOs, RTOs, and Non-Public Utility Transmission Providers

NOPR Proposal

224. The Commission did not specifically address the application of the ATC-related reforms proposed in the NOPR to ISOs and RTOs or non-public utility transmission providers.

Comments

225. ISOs and RTOs believe that the Commission should not require wholesale revisions of RTO and ISO tariffs, even on such issues as ATC standards.[161] They caution that many regional grid operators' tariffs contain nonconforming provisions that were the product of extensive debate, litigation and settlements. In addition, some commenters point out that concern about ATC calculations is a non-issue in many ISO/RTO regions because transmission services in those regions are not based on physical transmission reservations.[162]

226. MISO argues that AFC calculation methodologies should be established via the RTO stakeholder process, not NERC. In its reply comments, Exelon expresses disagreement with MISO and states that there must be one standard for ATC calculations, not several methods based on the desires of different sets of stakeholders. Several commenters also believe that ISOs/RTOs should not be exempt from the requirements for consistent and transparent ATC calculations.[163]

227. EEI asks the Commission to require all municipal and other non-public utility transmission providers to adhere to any requirement for consistent and transparent ATC/AFC calculation. In its view, applying the ATC-related reforms to these nonjurisdictional entities would recognize the interconnected nature of the transmission grid. EEI argues that greater transparency and consistency in the provision of transmission service would be frustrated if all transmission providers do not have to comply. Other commenters reply that EEI's concerns are unfounded and describe an example in the WECC region, where the methodologies and practices regarding ATC calculations are developed by representatives from all affected transmission providers, utilities, and market participants, including nonjurisdictional entities.[164]

228. LPPC contends that the NERC reliability standards related to ATC calculation will already be applicable to both public and non-public utilities. LPPC argues that NERC standards, when final, will be filed with the Commission, become part of the ERO's mandatory reliability standards and will be fully applicable to otherwise nonjurisdictional entities. As a result, the ATC standards will be applicable to and enforceable upon all transmission owners, whether or not the transmission owner has an OATT.

Commission Determination

229. We discuss the applicability of the Final Rule to ISOs and RTOs in section IV.C.2 above. With respect to the application of the ATC requirements of this Final Rule to municipal and other non-public utility transmission providers, we likewise note that the applicability of the rule generally to such entities is addressed in section

[159] If ISOs and RTOs cannot perform the coordination function, New York Commission suggests the establishment of a Transmission Oversight Center to oversee the calculation of ATC within and between ISOs and RTOs.

[160] NAESB's work plan for developing business practices related to other reforms adopted in this Final Rule should be filed separately, as requested in Section IV.C.1.

[161] *E.g.*, PJM and MISO Transmission Owners, SPP Reply.

[162] *E.g.*, ISO/RTO Council, ISO New England, and Pennsylvania Commission.

[163] *E.g.,* NRECA and TDU Systems.

[164] *E.g.,* Lassen and Public Power Council.

IV.C.3. We note here, however, that such entities will be required to comply with reliability standards developed under FPA section 215. As LPPC acknowledges, once these reliability standards are approved they will become part of the ERO's mandatory reliability standards and, thus, will be applicable to and enforceable upon all transmission owners, whether or not the transmission owner has adopted the OATT.

d. Alternatives to ATC Consistency

Comments

230. Some commenters contend that the NOPR is focused too narrowly on simply improving the consistency and transparency of ATC determinations and suggest that a focus on balancing (or dispatch) services and how those are priced would allow the Commission to avoid the pitfalls inherent in the ATC approach.[165] In their view, such an approach would eliminate much of the difference between how third parties are treated in RTO versus non-RTO systems. Constellation encourages the Commission to consider requiring transmission providers to implement all-inclusive, security constrained economic dispatch processes. In reply comments, Chandley-Hogan argue that the Commission's ATC-related proposals in the NOPR confuse how transmission service is actually provided in most of the United States and, as a result, the Commission's analysis of perceived problems in the calculation of ATC is flawed, inconsistent with network realities and the laws of physics, and incompatible with reliable operations.

231. Contrary to the above claims, some commenters find that ATC provides a functionally useful measure of available capacity and has certain advantages over alternative models.[166] These commenters argue that the factual record does not support conclusions that bid-based, marginal cost dispatch by a third party is inherently more efficient or inherently more likely to remedy undue-discrimination than the OATT model, and cannot overcome the considerable real world obstacles to pure economic redispatch, including overlapping and dynamic constraints, and the physical realities in the Western Interconnection that often limit the pool of resources that can be redispatched to solve constraints. LPPC contends that the principal advantage of ATC is the certainty that it provides for available capacity, suggesting that the contract path paradigm facilitates long-term bilateral contracting.

Commission Determination

232. In this rulemaking, the Commission is requiring consistency in the determination of ATC with the purpose of improving a customer's ability to receive transmission service on a non-discriminatory basis. These reforms are fully consistent with operational reality, and we decline to mandate the security constrained economic dispatch alternative proposed by Chandley-Hogan. Chandley-Hogan argue that it would be unduly discriminatory to exclude third-party generators from an efficient dispatch to serve native load and therefore a centralized, bid-based market is required. We agree that a centralized bid-based market can benefit customers and, over a large region, can manage congestion efficiently. We do not believe, however, that mandating that result—essentially requiring that Day 2 RTOs be adopted in every region of the country—is necessary to remedy undue discrimination in the provision of transmission service. The concern raised by Chandley-Hogan is not related solely to the nondiscriminatory use of the transmission system. It also implicates the purchase decisions of transmission providers on behalf of their native load customers. These decisions are regulated primarily by the states and we decline to take generic action in this rulemaking to reform the processes by which those purchases are made.

e. ATC Components

233. The next several sections address components of ATC that must be made consistent to remove the potential for undue discrimination, namely TTC/TFC, ETC, CBM, and TRM.

(1) Total Transfer Capability (TTC)/Total Flowgate Capability (TFC)

NOPR Proposal

234. The Commission proposed to direct public utilities, working through NERC, to develop consistent practices for calculating total transfer/flowgate capability (TTC/TFC). Although the NERC reliability regions have historically calculated transfer capability using different approaches, the Commission expressed its view that guidelines for a common approach to calculating transfer capability are achievable. The Commission also stated that the criteria used for identifying flowgates and determining TFC could be more consistent.

Comments

235. Entergy supports the development of consistent practices for determining transfer capability while maintaining flexibility to recognize regional and system-specific differences. APPA agrees that the calculation of TTC/TFC is, for the most part, a regional calculation. APPA states that the Western Interconnection and ERCOT use their own methods, which are generally applied system-wide. APPA believes that more standardization and coordination of TTC/TFC among transmission providers in the Eastern Interconnection, where two primary methods are used to calculate TTC or TFC, would be desirable because of reported loop-flow problems in the Eastern Interconnection.

236. In order to increase transfer capability from existing facilities, AWEA proposes that the Commission direct NERC, as part of developing consistent ATC standards, to investigate the impact of implementing dynamic line ratings in TTC/TFC calculations and propose protocols to effectuate such a program. In response to AWEA's proposal, commenters state that if the Commission decides to provide guidance to NERC with regard to dynamic line ratings, the Commission should encourage NERC to develop standards with regard to dynamic line ratings in the operating horizon, but not in the planning horizon.[167]

Commission Determination

237. The Commission adopts the NOPR proposal and directs public utilities, working through NERC, to develop consistent practices for calculating TTC/TFC. We direct public utilities, working through NERC, to address, through the reliability standards process, any differences in developing TTC/TFC for transmission provided under the *pro forma* OATT and for transfer capability for native load and reliability assessment studies.

238. We acknowledge that reliability regions have historically calculated transfer capability using different approaches, and we agree that regional differences should be respected.[168] However, as already discussed above regarding ATC, the TTC requirements will be determined by the NERC reliability standards and any request for a regional difference from the reliability standards must take place through the NERC process.

[165] *E.g.,* Chandley-Hogan, EPSA, PJM, San Diego G&E, and Transparent Dispatch Advocates Reply.

[166] *E.g.,* APPA, CMUA, CPA, Duke, EEI, Entergy, LPPC, Public Power Council, Sacramento, and WestConnect Reply.

[167] *E.g.,* MAPP and MidAmerican.

[168] For example, WECC has a documented open process for establishing TTC for the Western Interconnection.

239. With respect to AWEA's proposal regarding implementing dynamic line ratings in TTC/TFC calculations, the Commission finds that this proposal is outside the scope of this rulemaking as it does not appear to relate to undue discrimination in transmission service and, in any event, would best be addressed in the first instance through the NERC reliability standards development process, addressing reliability standards that regulate facility ratings. If AWEA desires to pursue this proposal, it should propose an appropriate dynamic line rating standard within the ERO's reliability standards development process.

(2) Existing Transmission Commitments (ETC)

NOPR Proposal

240. In the NOPR, the Commission expressed its view that the lack of consistency in modeling of existing transmission commitments (ETC) resulted in excessive discretion in determining how much capacity a transmission provider sets aside for native load, including its network customers. The Commission therefore proposed the development of a consistent methodology for determining the capacity needed and set aside for native load usage. The Commission also proposed that accounting for transmission reservations in an ATC/AFC calculation be more consistent. The Commission further proposed that public utilities, working through NERC, establish and specifically identify the reservations to be used in determining ETC.

Comments

241. Entegra and PGP support increasing consistency in determining ETC. APPA agrees that it would be helpful to standardize the method of accounting for ETC on an interconnection-wide basis. APPA states, however, that flexibility might be required among the interconnections. TDU Systems requests that the Commission define with specificity the types of transmission service requests or scheduled transmission transactions that should be included in ETC and agrees with the Commission that inclusion of all requests for transmission service in ETC is likely to overstate usage of the system, thus understating ATC. It suggests that the Commission develop a bright line method for calculating ETC. NERC notes that its proposed reliability standards would define ETC and require appropriate documentation. NERC adds, however, that the components included in ETC appear to be candidates for business practices rather than reliability standards.

242. Williams proposes that ETC be the subject of an expanded definition and that native load growth projections be based on verifiable data provided by an independent source. It also states that transmission providers should be required to update ATC based on each confirmed transmission service reservation (point-to-point or network, firm or non-firm).

Commission Determination

243. To achieve greater consistency in ETC calculations and further reduce the potential for undue discrimination, the Commission adopts the NOPR proposal and directs public utilities, working through NERC and NAESB, to develop a consistent approach for determining the amount of transfer capability a transmission provider may set aside for its native load and other committed uses. We expect that NERC will address ETC through the MOD–001 reliability standard rather than through a separate reliability standard.[169] By using MOD–001, the ETC calculation can be adjusted to be applicable to each of the three ATC methodologies under development by NERC.

244. In order to provide specific direction to public utilities and NERC, we determine that ETC should be defined to include committed uses of the transmission system, including (1) Native load commitments (including network service), (2) grandfathered transmission rights, (3) appropriate point-to-point reservations,[170] (4) rollover rights associated with long-term firm service, and (5) other uses identified through the NERC process. ETC should not be used to set aside transfer capability for any type of planning or contingency reserve, which are to be addressed through CBM and TRM.[171] In addition, in the short-term ATC calculation, all reserved but unused transfer capability (non-scheduled) shall be released as non-firm ATC.

245. We agree with TDU Systems that inclusion of all requests for transmission service in ETC would likely overstate usage of the system and understate ATC. We therefore find that reservations that have the same point of receipt (POR) (generator) but different point of delivery (POD) (load), for the same time frame, should not be modeled in the ETC calculation simultaneously if their combined reserved transmission capacity exceeds the generator's nameplate capacity at POR. This will prevent overly unrealistic utilization of transmission capacity associated with power output from a generator identified as a POR. We direct public utilities, working through NERC, to develop requirements in MOD–001 that lay out clear instructions on how these reservations should be accounted. One approach that could be used is examining historical patterns of actual reservation use during a particular season, month, or time of day.

246. We agree with NERC that some elements of ETC are candidates for business practices rather than reliability standards. Accordingly, we direct public utilities, working through NAESB, to develop business practices necessary for full implementation of the developed MOD–001 reliability standard.

247. We decline to adopt Williams's proposal to require that native load growth be based on the verifiable data provided by an independent source. Through increased consistency and transparency of ATC determinations, including requirements for posting additional data, third parties will be able to verify the accuracy of ETC, helping to eliminate opportunities for undue discrimination.

(3) Capacity Benefit Margin (CBM)

NOPR Proposal

248. In the NOPR, the Commission proposed three options to address the CBM component of ATC: (1) Have NERC develop clear standards for how the CBM value should be determined, allocated across transmission paths, and used; (2) charge an entity for which transfer capability has been set aside to meet generation reliability criteria a separate rate for this service; or (3) eliminate CBM and require an entity reserving ATC to meet generation reserve (currently through CBM) to designate network resources on the other side of the interface and make an associated transmission service reservation.

Comments

249. Numerous commenters support the Commission's proposed option one, requiring NERC to develop clear standards for how the CBM value should be determined, allocated across

[169] The purpose of MOD–001 is to promote the consistent and uniform application of transfer capability calculations among the transmission system users.

[170] By ''appropriate,'' we mean that reservations accounted for under ETC depend on the firmness and duration of the reservation. The specific characteristics should be developed in the reliability standard.

[171] TRM also includes such things as loop flow and parallel path flow.

transmission paths, and used.[172] They believe that CBM ensures the ability to import needed power to support system conditions. TVA argues that option two would be costly and may cause some systems to forego CBM, thereby jeopardizing service to native load customers. PJM states that option two is irrelevant in PJM since PJM ''totals'' reservations and decides when CBM can be used. Supporters of option one criticize option three, elimination of CBM, as costly and a threat to transmission system reliability. Southern, Progress Energy, and PJM emphasize that, without CBM, the LSEs would need to increase their reserve margin by contracting for additional generation capacity, costing millions of dollars. In addition, Ameren and TVA believe that CBM elimination will increase the likelihood of widespread blackouts in emergency conditions.

250. At the October 12 Technical Conference, Exelon supported option two proposing a charge for CBM. Exelon contended that, in a rate-making context, there would be an increase in the divisor of the rate by the amount of CBM set-aside which would lower the point-to-point charge. Consequently, those not benefiting from the CBM set-aside effectively would be paying a lower charge.

251. Constellation and Morgan Stanley support the elimination of CBM and argue that CBM and TRM are often used interchangeably and result in duplicative transmission set-asides. They also argue that there is no compelling need for CBM in the current liquid market environment. In addition, Morgan Stanley states that LSEs affiliated with the transmission provider should not be allowed to use CBM for long-term planning purposes as an excuse to avoid undertaking needed resource additions or to conceal the true cost of their load serving functions. Furthermore, the Commission should not be distracted by assertions that such long-term arrangements are necessary for ''reliability,'' when in fact they are simply a way to protect the economic interests of a particular entity.

252. Duke replies that Constellation mistakenly believes that CBM is currently only available to a transmission provider's native load when, in fact, for those transmission providers that establish CBM, it should be established for the load of all LSEs in the control area. Duke contends that not all transmission providers set aside capacity through CBM for their native load; to the extent that a transmission provider does not set aside CBM, there should be no obligation to allow other LSEs to do so. Duke proposes that the Commission should continue to permit such flexibility.

253. NERC takes no position on CBM, expecting that the issue can be settled through the NERC and NAESB Procedure for Joint Standards Development and Coordination and through other open forums.

254. TAPS suggests that the Commission ensure that all LSEs have both access to CBM to meet their reserve-sharing needs and meaningful input into how much CBM is reserved. To do so, TAPS recommends the creation of a reserve-sharing group made up of the transmission provider and LSEs it serves. It argues that this would remove reservation decisions from the sole discretion of the vertically-integrated transmission provider and instead have them made by the transmission provider/LSE reserve-sharing group, subject to dispute resolution at the Commission. All LSEs would be invited to participate in the studies as well as review the results and assumptions. Moreover, once a regional planning process is established, as proposed in the NOPR, TAPS recommends that the regional planning group be required to approve the CBM reservation as well.

255. Williams suggests that a transmission provider must designate network resources and reserve firm transfer capability on both sides of the control area transmission interface in order to reserve CBM. Duke replies that, although some commenters prefer eliminating CBM and replacing it with additional designated network resources, CBM is the preferable option because it is less costly. Duke further argues that the choice is between setting aside both additional transmission and generation capacity to deal with emergencies (the additional designated network resource approach) versus setting aside only transmission (the CBM approach). Having to procure additional designated network resources to keep in reserve reduces one of the main benefits of interconnected operations. Duke argues that eliminating CBM would drive up costs for network customers, as they would have to procure additional generation and transmission resources. EEI adds that such a proposal may result in increased LSE reserve requirements, over-building of generation supply, and a reduction, rather than an increase, in ATC.

Commission Determination

256. The Commission concludes that it is appropriate to allow LSEs to retain the option of setting aside transfer capability in the form of CBM to maintain their generation reliability requirement. We agree with commenters that, without CBM, LSEs would have to increase their generation reserve margins by contracting for generation capacity, which may result in higher costs without additional reliability benefits. We require, however, the development of standards for how CBM is determined, allocated across transmission paths, and used in order to limit misuse of transfer capability set aside as CBM. Transmission providers also must reflect the set-aside of transfer capability as CBM in the development of the rate for point-to-point transmission service to ensure comparable treatment for point-to-point to customers.

257. The Commission therefore adopts a combination of the NOPR options one and two, and declines to adopt option three. First, we require public utilities, working through NERC and NAESB, to develop clear standards for how the CBM value shall be determined, allocated across transmission paths, and used. We understand that NERC has already begun the process of modifying several of the CBM-related reliability standards and that the drafting process is a joint project with NAESB. Second, we require transmission providers to reflect the set-aside of transfer capability as CBM in the development of the rate for point-to-point transmission service.

258. We note that there is broad concern that eliminating CBM (option three) would impose extraordinary costs for meeting generation reliability criteria, which then may lead utilities to reduce their generation reliability requirement to avoid the cost increase. We believe that the reforms reflected in combining options one and two are sufficient to remedy undue discrimination and that the adverse effects associated with option three are neither warranted nor required. We reject Morgan Stanley's call for CBM elimination on the grounds that CBM is acting as a disincentive to undertake needed generation resource additions. It would be inappropriate for the Commission to restrict the ability of an LSE to determine how best to meet its generation reliability criteria.

259. To ensure CBM is used for its intended purpose, CBM shall only be used to allow an LSE to meet its generation reliability criteria. Consistent with Duke's statement, we clarify that

[172] *E.g.,* Allegheny, Ameren, EEI, Duke, NRECA, TVA, APPA, Bonneville, EPSA, FirstEnergy, Indianapolis Power, MidAmerican, Pinnacle, PJM, PGP, PNM–TNMP, Public Power Council, Sacramento, Seattle, South Carolina E&G, TANC, TDU Systems, and Wisconsin Electric.

each LSE within a transmission provider's control area has the right to request the transmission provider to set aside transfer capability as CBM for the LSE to meet its historical, State, RTO, or regional generation reliability criteria requirement such as reserve margin, loss of load probability (LOLP), the loss of largest units, *etc.*

260. We direct public utilities, working through NERC, to develop clear requirements for allocating CBM over transmission paths and flowgates. While we do not mandate a particular methodology for allocating CBM to paths and flowgates, one approach could be based on the location of the outside resources or spot market hubs that an LSE has historically relied on during emergencies resulting from an energy deficiency.

261. We concur with TAPS' proposal that all LSEs should have access to CBM and meaningful input into how much transfer capability is set aside as CBM. In the transparency section below, we provide detailed requirements regarding availability of documentation used to determine the amount of transfer capability to be set aside as CBM and the posting of CBM values and narratives. Access to this documentation will enable LSEs to validate how much transfer capability is set aside as CBM on each system and provide them with information to question whether the set-aside is consistent with the reliability standards and this Final Rule.

262. Concerning TAPS' proposal to remove the reservation decision from the sole discretion of transmission providers, we determine that LSEs should be permitted to call for use of CBM, if they do so pursuant to conditions established in the reliability standards development process. We direct public utilities working through NERC to modify the CBM-related standards to specify the generation deficiency conditions during which an LSE will be allowed to use the transfer capability reserved as CBM. In addition, we direct that transmission set aside as CBM shall be zero in non-firm ATC calculations. Finally, we order public utilities to work with NAESB to develop an OASIS mechanism that will allow for auditing of CBM usage.

263. We also require transmission providers to design their transmission charges to ensure that the class of customers not benefiting from the CBM set-aside, *i.e.*, point-to-point customers, do not pay a transmission charge that includes the cost of the CBM set-aside. To do this, transmission providers are required to submit redesigned transmission charges that reflect the CBM set-aside through a limited issue FPA section 205 rate filing as part of its initial ATC-related compliance filing. These filings, which may be submitted within 120 days after the publication of the Final Rule in the **Federal Register**, may be limited to the rate design change only, *i.e.*, they will not require the submission of cost of service data or a revision to the transmission provider's revenue requirement.

264. With respect to TAPS' proposal that all LSEs should be allowed to use CBM to meet their reserve-sharing needs, we believe that TRM is the appropriate category for that purpose, not CBM. We reject TAPS' proposal to use CBM for the LSE's reserve-sharing needs, but instead make TRM available for the incremental power flows resulting from reserve sharing, as explained next.

265. As we are rejecting option three, which would have required the reservation of transfer capability rather than using CBM, we also reject Williams' proposal to require the reservation of transfer capability on both sides of an interface for CBM.

(4) Transmission Reserve Margin (TRM)

NOPR Proposal

266. Finally, the Commission proposed the development of reliability standards MOD–008 and MOD–009 [173] that specify the uncertainties that TRM could be used to accommodate, which could include (1) Load forecast and load distribution error, (2) variations in facility loadings, (3) uncertainty in transmission system topology, (4) loop flow impact, (5) variations in generation dispatch, including intermittent resources, (6) automatic sharing of reserves, and (7) other uncertainties identified through the NERC reliability standards development process.

Comments

267. Most commenters agree that the existing definitions for TRM require clarification.[174] Commenters also agree that NERC should be required to develop clear standards for the determination of TRM, including specifying the criteria used in the determination of TRM.[175] PNM–TNMP supports the Commission's proposal, pointing out that the implementation of the current NERC standards definition for TRM and CBM could result in its double-counting, which must be eliminated. APPA members in the Western Interconnection suggest that regional variations be permitted. They also note that the modeling methods used by WECC and its sub-regions may differ from those used in the Eastern Interconnection. For example, they contend that uncertainties associated with transmission maintenance schedules that are driven by hydro-production curves will seasonally affect TRM set-asides on certain transfer paths. PJM believes that the TRM methodology should be consistent at the regional reliability organization level. PJM also contends that TRM should be coordinated, exchanged and respected on external flowgates and that the concept of a maximum TRM, by percentage, should be adopted in the NERC standards.

268. Consistent with its position on CBM, TAPS proposes that TRM set-asides should be conditioned on inclusive reserve-sharing arrangements, with the reservations determined by the reserve-sharing group, subject to dispute resolution before the Commission (and, eventually, approval by joint planning groups).

269. PNM–TNMP suggests that the Commission consider definitions to include the following clarification taken from WECC procedures on ATC: ''If the limitation on the use of TRM to 59 minutes would force a Transmission Provider to set aside unnecessary CBM on the same path as the TRM, that Transmission Provider may utilize the TRM beyond the 59 minutes.'' [176] PNM–TNMP states that this would allow the transmission provider to maximize the ATC by not needlessly setting aside twice the amount of transmission (TRM and CBM) than is necessary for reliability.

270. Nevada Companies argue that no new standards are required for TRM and that any further action would be burdensome. They explain that NERC has a well-established definition that does not require further clarification. In their view, all that is required is a complete statement, to be posted on OASIS, regarding the transmission provider's application of TRM. NERC

[173] The MOD–008 and MOD–009 reliability standards document regional TRM methodologies and procedures for verifying TRM values.

[174] *E.g.*, Allegheny, APPA, EEI, EPSA, Exelon, LPPC, MidAmerican, NRECA, Northwest IOUs, NorthWestern, Occidental, Pinnacle, Powerex, PNM–TNMP, PPL, PJM, PPM, and WestConnect.

[175] Exelon recommends that the following factors should be the same for the planning process and ATC/AFC process to achieve consistency: base case flows, reservation impacts, TRM and CBM forecasted to occur simultaneously; counterflows; positive impacts resulting from reservations and generation dispatch; TRM for the same scenarios; and CBM.

[176] *Citing* WECC Rocky Mountain Operating and Planning Group, *Determination of Available Transfer Capability within the Western Interconnection, June 2001, page 9, http://www.wecc.biz/modules.php?op=modload&name=Downloads&file=index&req=getit&lid=1035.*

comments that the existing reliability standards for TRM will be revised to require clear documentation of the calculation of TRM. It also adds that the revised standard will make various TRM components mandatory to achieve more consistency across methodologies.

271. Santee Cooper urges the Commission to ensure that service to native load and transmission system reliability will not be compromised as the Commission seeks greater levels of consistency in the calculation of ATC. It states that the Commission also must be cognizant of the importance of TRM in the provision of service to native load.

Commission Determination

272. The Commission adopts the NOPR proposal and requires public utilities, working through NERC, to complete the ongoing process of modifying TRM standards MOD–008 and MOD–009. We understand that the standard drafting process is underway as a joint project with NAESB.

273. The Commission also adopts the NOPR proposal to establish standards specifying the appropriate uses of TRM to guide NERC and NAESB in the drafting process. Transmission providers may set aside TRM for (1) Load forecast and load distribution error, (2) variations in facility loadings, (3) uncertainty in transmission system topology, (4) loop flow impact, (5) variations in generation dispatch, (6) automatic sharing of reserves, and (7) other uncertainties as identified through the NERC reliability standards development process. Because load, facility loading and other uncertainties constantly deviate, we will not require that TRM set aside capacity be set at zero in the non-firm ATC calculation. In other words, we will not require transfer capability that is set aside as TRM to be sold on a non-firm basis. We find that clear specification in this Final Rule of the permitted purposes for which entities may reserve CBM and TRM will virtually eliminate double-counting of TRM and CBM.

274. We will not adopt PNM-TNMP's proposal regarding use of set aside transfer capability as TRM beyond 59 minutes, rather than converting it to CBM. Our proposal is to separate transfer capability set asides as either CBM or TRM without regard to duration of use of the set aside. Therefore, such a clarification is not necessary.

275. In addition, we direct public utilities, working through NERC, to establish an appropriate maximum TRM. One acceptable method may be to use a percentage of ratings reduction, *i.e.*, model the system assuming all facility ratings are reduced by a specific percentage. This is a relatively simple method and, if adopted as the reliability standard's method, should not restrict a transmission provider from using a more sophisticated method that may allow for greater ATC without reducing overall reliability.

276. Because of the operational characteristics of the uncertainties that are to be accommodated using TRM, and their aggregate impact on reliable operation, we require each transmission provider to calculate, and allocate on the paths and flowgates, the aggregate TRM value for all LSEs within its area. We support NERC's plan to revise existing reliability standards for TRM to require clear documentation of the TRM calculation, as we expect the TRM value to be supported and fully transparent. In addition, we require each transmission provider to make available all underlying documentation, including work papers and load flow base cases, used to determine TRM, to any transmission customer and LSE within its control area, subject to a confidentiality agreement,[177] if necessary. We agree with Santee Cooper's comments that the Commission must ensure that service to native load and system reliability are not compromised. We believe that our requirement for public utilities to work through NERC satisfies such concerns.

277. With respect to the proposal to permit regional variations in the TRM calculation methodology, we reiterate our position stated above that any request for regional difference from the applicable reliability standards must take place through the NERC reliability standards development process. With respect to TAPS' proposal regarding reserve sharing groups, we clarify that, to the extent transfer capability is needed for transmission of shared reserves, this is included under TRM. However, as noted previously in the CBM discussion, we are not mandating the use of reserve sharing groups.

f. Modeling, Assumptions and Input Data

NOPR Proposal

278. The Commission's proposal with regard to modeling, assumptions and data inputs was based on a principle that there should be consistency among transmission providers and between what the transmission provider does for its operation and expansion planning for native load and what it does in determining short and long-term ATC for all uses. The Commission stated its view that consistency is necessary to ensure non-discriminatory treatment by eliminating a transmission provider's ability to use discretion to the disadvantage of competitors. The Commission proposed three specific areas for reform.

279. First, the Commission proposed to require public utilities, working through NERC, to modify the ATC-related standards to incorporate a requirement for periodic validation and modification of models to ensure that they are up to date.[178] The Commission stated that the models should be updated and benchmarked to actual events.

280. Second, the Commission proposed that, to the maximum extent practicable, the same data must be used by the transmission provider to determine short- and long-term ATC as those used in system operation and planning studies, respectively.

281. Third, the Commission proposed that public utilities, working through NERC, develop assumptions for use in ATC determinations and that the assumptions remain consistent among transmission providers to the maximum extent practicable. The Commission indicated that short- and long-term ATC calculations should be developed using consistent assumptions regarding representative load levels, generation dispatch, transmission reservations and counterflows, in addition to any other modeling assumptions identified by NERC. The Commission further proposed that there should be a consistent approach to the modeling of load levels, a method established for determining which generators should be modeled in service (including guidance on how independent generators should be considered), consistency in the simulation of power flows from points of receipt to delivery when sources are unknown, and consistency in the manner in which ATC/AFC reservations are accounted for. The Commission stated that the model for long-term ATC should include, to the maximum extent practicable, the same assumptions regarding new transmission and generation facilities additions and retirements as those used in planning for expansion.

282. The Commission noted that the proposal is not intended to change the manner in which native load is served

[177] The agreement may appropriately restrict the sharing of sensitive information with customer personnel that are involved only in transmission functions, as opposed to merchant functions.

[178] The Commission noted that this would include review of load flow base cases, short circuit data, transient and dynamic stability simulation data, contingency (files should contain information on special protection schemes and remedial action plans) subsystem and monitoring files, and production cost models.

and sought comment on whether (and, if so, how) this proposal would affect service to native load customers.

Comments

283. Commenters generally discuss consistency of data, assumptions and modeling together so we in turn do the same. Many commenters support the proposals for consistency in data, assumptions and/or modeling.[179] Others support flexibility or regional variation.[180] A few commenters oppose specific aspects of the overall proposal.[181]

284. TDU Systems and Sacramento express support for the Commission's proposal to require public utilities, working through NERC, to develop modeling assumptions for use in calculating ATC that are consistent with those used to plan the operation and expansion of the transmission system. Xcel, however, would have the Commission go further. Xcel recommends that the Commission enhance its proposal by establishing a date certain for transmission providers in the Western Interconnection to be required to account for impacts of loop flows when processing transmission service requests and calculating ATC. Xcel suggests that NERC be directed to develop standards for evaluation of counterflows on ATC. EPSA offers examples of specific data inputs that, in its view, should also be standardized among all transmission providers, which include: Load levels and distribution studies; transmission outages; generation outages; and generation dispatch. Ameren submits that any modeling of base generation dispatch must model generators, including merchant generators, as they are expected to run.

285. Williams asks the Commission to require consistency between transmission planning horizon and procurement terms, and transparency around the long-term transmission planning assumptions. Williams states that third-party bids to a request for proposals are evaluated with transmission costs that may already be included in long-term transmission plans. Thus, argues Williams, procurement and long-term planning assumptions are intertwined. In reply, Entergy acknowledges and agrees that the models used for planning, operations and service request evaluations should generally be based on similar data and procedures, but argues that due to changes in system configuration, facilities included in transmission plans are often not needed at all and thus are not constructed. Therefore, Entergy proposes that the Commission allow NERC to determine the circumstances under which differences between models would be appropriate.

286. Southern asks for clarification on what the Commission intends by proposing that modeling assumptions be consistent in the context of TTC assessments. Southern explains that, as the Commission has recognized, the inevitable changes in system conditions between different time horizons (*e.g.,* real-time and planning and operations) would render this approach unreliable because load levels, dispatch arrangements, reservations, and outages cannot be the same over significantly different time horizons.

287. Supporting regional differences, Bonneville contends that calculating ATC for a hydroelectric system requires different inputs and modeling assumptions than are appropriate for thermal-based systems. Bonneville explains that non-power constraints placed on hydroelectric projects that were built for multiple uses are a major concern on the Bonneville system. Consequently, hydro operators are more limited in their ability to use generation redispatch as a tool to meet long-term firm load obligations. Similarly, Santee Cooper cautions that over-standardization may result in certain parameters being misstated or inappropriately constrained, resulting in inaccurate reservations of capacity for native load purposes and a potentially detrimental effect on the reliability of service. It recommends that the Commission direct NERC to allow deviations from the standard modeling assumptions where the need can be supported, with the caveat that a utility's modeling assumptions must be transparent and available for scrutiny. Seattle contends that modeling assumptions should be developed at the sub-regional level, consistent among adjacent transmission providers. TVA suggests that the transmission providers be allowed to retain flexibility to conduct risk analyses and reflect those in their modeling assumptions.

288. Other commenters argue that modeling assumption standardization should not be performed by NERC and, instead, should be delegated to the regional reliability organizations or RTOs, as they possess a superior knowledge of the physical grid within their boundaries.[182] PJM states that such issues are best left to the joint stakeholder processes and the resulting joint and common market initiatives.

289. In response to the Commission's inquiry as to how standardizing the modeling assumptions and data would affect native load, commenters generally state that standardization of ATC modeling assumptions would increase comparability of service to LSEs and enhance the ATC methodology and its nondiscriminatory application to grid utilization.[183]

Commission Determination

290. The Commission directs public utilities, working through NERC, to modify the reliability standards MOD–010 through MOD–025 [184] to incorporate a requirement for the periodic review and modification of models for (1) Load flow base cases with contingency, subsystem, and monitoring files, (2) short circuit data, and (3) transient and dynamic stability simulation data, in order to ensure that they are up to date. This means that the models should be updated and benchmarked to actual events. We find that this requirement is essential in order to have an accurate simulation of the performance of the grid and from which to comparably calculate ATC, therefore increasing transparency and decreasing the potential for undue discrimination by transmission providers.

291. We note that commenters generally were very supportive of the Commission's proposals for review and update of models and for consistency of assumptions and data inputs. We received no adverse comments concerning our general proposal to require public utilities, working through NERC, to modify the ATC-related standards to incorporate a requirement for the periodic review and modification of models to ensure that they are up to date. Moreover, the need to improve the quality of system modeling was one of the U.S.-Canada Power System Task Force recommendations.[185]

292. The Commission also adopts the NOPR proposal to require transmission providers to use data and modeling assumptions for the short- and long-term ATC calculations that are consistent with that used for the

[179] *E.g.,* APPA, Arkansas Commission, Constellation, Entegra, Exelon, EPSA, ISO/RTO Council, LDWP, MidAmerican, Municipals, NRECA, CREPC, Sacramento, Santee Cooper, Suez Energy NA, TAPS, TDU Systems, WestConnect, and Williams.

[180] *E.g.,* Bonneville. Santee Cooper, and Entergy.

[181] *E.g.,* PJM, EPSA, and Ameren.

[182] *E.g.,* Sacramento, Manitoba Hydro, Nevada Companies, and TANC.

[183] *E.g.,* Sacramento.

[184] The MOD–010 through MOD–025 reliability standards establish data requirements, reporting procedures, and system model development and validation for use in the reliability analysis of the interconnected transmission systems.

[185] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations.*

planning of operations and system expansion, respectively, to the maximum extent practicable. This includes, for example: (1) Load levels, (2) generation dispatch, (3) transmission and generation facilities maintenance schedules, (4) contingency outages, (5) topology, (6) transmission reservations, (7) assumptions regarding transmission and generation facilities additions and retirements, and (8) counterflows. We find that requiring consistency in the data and modeling assumptions used for ATC calculations will remedy the potential for undue discrimination by eliminating discretion and ensuring comparability in the manner in which a transmission provider operates and plans its system to serve native load and the manner in which it calculates ATC for service to third parties. The Commission directs public utilities, working through NERC, to modify ATC standards to achieve this consistency.

293. With regard to EPSA's request for the standardization of additional data inputs, we believe they are already captured in the Commission's proposal as adopted in this Final Rule. Xcel asks the Commission to require consistency in the determination of counterflows in the calculation of ATC. Counterflows are included in the list of assumptions that public utilities, working through NERC, are required to make consistent. We believe that counterflows, if treated inconsistently, can adversely affect reliability and competition, depending on how they are accounted for. Accordingly, we reiterate that public utilities, working through NERC and NAESB, are directed to develop an approach for accounting for counterflows, in the relevant ATC standards and business practices. We find unnecessary Xcel's request that we require a date certain for specific issues in the Western Interconnection to be addressed. Above we require public utilities, working through NERC, to modify the ATC standards within 270 days after the publication of the Final Rule in the **Federal Register**.

294. With regard to Williams' request that the Commission require consistency between transmission planning horizons and procurement terms, we believe that such an express requirement is neither appropriate nor necessary. The manner in which transmission providers procure power for native load customers is generally outside the scope of this rulemaking. This notwithstanding, we note that by this Final Rule, Williams and other affected market participants will have an opportunity to participate in a transmission provider's coordinated, regional planning process. This will provide a vehicle for interested parties to gain access to planning-related information and to have their own plans for transmission evaluated at the same time the transmission provider plans for its needs. Coupled with the modifications to the ATC-related reliability standards that require the same data and assumptions to be used for calculating long-term ATC as in system planning, these reforms are adequate to address Williams' concern. To the extent there are changes on the system, these should be captured in the regional transmission planning process and in the determination of ATC. We therefore reject Entergy's proposal to allow NERC to determine the circumstances under which differences between models would be appropriate in order to ensure comparable service for all transmission customers.

295. We offer the following clarifications. In response to Southern, we clarify that we require consistent use of assumptions underlying operational planning for short-term ATC and expansion planning for long-term ATC calculation. We also clarify that there must be a consistent basis or approach to determining load levels. For example, one approach may be for transmission providers to calculate load levels using an on- and off-peak model for each month when evaluating yearly service requests and calculating yearly ATC. The same (peak- and off-peak) or alternative approaches may be used for monthly, weekly, daily and hourly ATC calculations. Regardless of the ultimate choice of approach, it is imperative that all transmission providers use the same approach to modeling load levels to enable the meaningful exchange of data among transmission providers. Accordingly, we direct public utilities, working through NERC, to develop consistent requirements for modeling load levels in MOD–001 for the services offered under the *pro forma* OATT.

296. With respect to modeling of generation dispatch, we direct public utilities, working through NERC, to develop requirements in NERC's MOD–001 reliability standard specifying how transmission providers shall determine which generators should be modeled in service, including guidance on how independent generation should be considered. We agree with Ameren that any modeling of base generation dispatch must model generators, including merchant generators, as they are expected to run. Accordingly, we direct public utilities, working through NERC, to revise reliability standard MOD–001 by specifying that base generation dispatch will model (1) All designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run and (2) uncommitted resources that are deliverable within the control area, economically dispatched as necessary to meet balancing requirements.

297. Regarding transmission reservations modeling, we direct public utilities, working through NERC, to develop requirements in reliability standard MOD–001 that specify (1) A consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown and (2) how to model existing reservations.

298. In response to commenter requests in favor of flexibility and regional differences, we again require that any waivers from the approved NERC reliability standards must take place through the NERC reliability standards process as a request for regional difference. Also, we disagree with commenters who argue that modeling assumptions should be delegated to regional reliability organizations. The goal of this rulemaking is to increase consistency in ATC calculations and that is best accomplished through NERC, which has established processes to address requests for regional differences from the reliability standard requirements. We conclude that the NERC process is appropriate as it is open to all industry participants and, therefore, is a suitable arena for establishment of common standards for modeling assumptions.

g. ATC Calculation Frequency

NOPR Proposal

299. The Commission proposed the development of standards requiring that the ATC calculation be performed with consistent frequency among transmission providers. Specifically, the Commission proposed that transmitting public utilities, working through NERC and NAESB, develop standards requiring that the calculation be performed by all transmission providers on a consistent time interval and in a manner that closely reflects the actual topology of the system, *e.g.*, generation and transmission outages, load forecast, interchange schedules, transmission reservations, facility ratings, and other necessary data. The Commission also supported uniform updating of ATC values and its components (*e.g.*, TTC, ETC, CBM, and TRM).

Comments

300. Alcoa and Powerex emphasize the critical need for ATC to be calculated more frequently for

constrained facilities. On constrained paths, where transmission equipment is stressed to its limits, Alcoa recommends that ATC be calculated on an hourly or real-time basis and be adjusted for temperature extremes. Seattle comments that ATC should be updated on a ''by exception'' basis, *i.e.*, when significant model changes or confirmations of service requests occur. While supporting the Commission proposal, TAPS cautions against updating ATC/AFC too frequently, as this may play into the hands of those who use reservation computer programs.

Commission Determination

301. The Commission adopts the NOPR proposal and requires the development of reliability standards that ensure ATC is calculated at consistent intervals among transmission providers. The Commission thus directs public utilities, working through NERC and NAESB, to revise reliability standard MOD–001 to require ATC to be recalculated by all transmission providers on a consistent time interval and in a manner that closely reflects the actual topology of the system, *e.g.*, generation and transmission outages, load forecast, interchange schedules, transmission reservations, facility ratings, and other necessary data. This process must also consider whether ATC should be calculated more frequently for constrained facilities. ATC-related requirements for OASIS posting are discussed below.

h. Data Exchange

NOPR Proposal

302. The Commission proposed the development through NERC of standard protocols that would enable and require the exchange of data and coordination among transmission providers. The Commission proposed that the following data, at a minimum, be exchanged among transmission providers for the purposes of ATC modeling: (1) Load levels; (2) transmission planned and contingency outages; (3) generation planned and contingency outages; (4) base generation dispatch; (5) existing transmission reservations, including counterflows; (6) ATC recalculation frequency and times; and (7) source/sink modeling identification. The Commission expressed its view that significant improvements in the communication, coordination, and exchange of data across all transmission providers in an interconnection are needed to produce accurate determinations of ATC. The Commission sought comment as to how much data sharing is workable, whether there are additional data that should be provided, whether access to such data should be limited to transmission providers, and if there are existing forums by which these or similar data are already shared.

Comments

303. Most commenters support the Commission's proposal to establish rules for data exchange, but express a preference for confidential data exchange.[186] NERC states that proposed changes to its existing modeling standards would require transmission providers to coordinate the calculation of TTC/ATC/AFC with others. TVA emphasizes that it has already incorporated these principles into its operating processes by executing agreements that provide for data exchange and coordination with neighboring transmission systems.

304. PJM suggests that the data exchange protocols be developed as minimum requirements and not interfere with existing protocols that PJM has with neighboring control areas under agreements such as the MISO/PJM JOA.[187] Similarly, SPP states that it also has developed seams coordination agreements with adjoining transmission providers [188] that fully meet and, in some cases exceed, the Commission's objective of fostering greater data exchanges between transmission providers.

305. MISO is concerned that the NOPR does not address transparency and regional coordination issues arising at the seams between RTO and non-RTO regions, particularly with respect to ATC calculations. In MISO's view, the Commission-approved joint operating agreements between various ISOs and RTOs contain cutting edge ATC calculation methodologies, while no comparable common protocols have evolved with non-RTO utilities. In its reply comments, Exelon agrees with MISO that the various joint operating agreements are not consistent. Exelon proposes that the NERC standards specify requirements for coordination and the type of data that must be exchanged and used for accurate ATC calculations. Exelon contends that having uniform standards for coordination developed by NERC will enhance efficiency throughout the industry, particularly between and among RTO and non-RTO areas. MidAmerican reiterates that ATC coordination remains an issue for RTOs and that any improvements in ATC coordination resulting from this proceeding must apply to the OATTs of RTOs and non-RTOs alike.

306. NAESB states that coordination and data exchange may require business practices for existing transmission reservations, including counterflows, ATC calculation frequency, and source/sink modeling identification. Some commenters request that the Commission clarify that only information necessary for purposes of ATC modeling needs to be exchanged.[189] In particular, they propose that proprietary generation or market information data that might harm their competitive position should not be publicly disseminated since that would not enhance the ability of transmission providers to accurately calculate ATC.

307. While acknowledging these confidentiality and commercial sensitivity concerns, other commenters recommend that the availability of shared data not be limited to transmission providers.[190] For example, TAPS explains that transmission dependent utilities need an opportunity to access the data periodically as a check on the process. To address confidentiality or standards of conduct concerns, TAPS proposes that transmission dependent utilities' access to data could be achieved through an employee barred from disclosing information to marketing staff or a third party independent consultant retained by the transmission dependent utility. However, APPA and Seattle urge the Commission to eliminate artificial and institutional barriers to the exchange of data and information.

308. APPA and Seattle also contend that, even if data were openly available, the vast quantities of hourly data points are difficult to manage, process and analyze using existing methods. To address this issue, APPA recommends

[186] *E.g.*, Allegheny, Ameren, Arkansas Municipal, Bonneville, Constellation, CAISO, Entergy, Exelon, FirstEnergy, LPPC, MidAmerican, Santee Cooper, Seattle, and TAPS.

[187] Under the PJM/MISO Joint Operating Agreement (JOA) and other operating agreements modeled on that agreement, parties have developed comprehensive data exchange protocols to facilitate coordination and consistent AFC calculations. Much of this data is supplied through industry standard sources such as NERC SDX and NERC eTags.

[188] SPP has developed seams agreements to exchange ATC data and coordinate congestion with non-RTO neighbors such as the Southwest Power Administration. Further, SPP exchanges ATC/AFC data and coordinates planning, reserve sharing, outage coordination, and transmission service administration under a transmission coordination agreement with Associated Electric Cooperative, Inc. (AECI), an individual transmission provider situated on SPP's border that is not a member of SPP or any other RTO.

[189] *E.g.,* Allegheny, Constellation, and Indianapolis Power.

[190] *E.g.,* APPA, Bonneville, TAPS, and Seattle.

that the Commission encourage ongoing efforts to obtain greater resolution of system-model State variables, contractual uses and probabilistic ranges and to refine data management and analytical methods.

309. New York Commission suggests having an overarching entity, such as a Transmission Oversight Center, that is responsible for calculating and coordinating ATC between various ISOs/RTOs could overcome this lack of data.

Commission Determination

310. The Commission adopts the NOPR proposal and directs public utilities, working through NERC, to revise the related MOD reliability standards to require the exchange of data and coordination among transmission providers and, working through NAESB, to develop complementary business practices. The following data shall, at a minimum, be exchanged among transmission providers for the purposes of ATC modeling: (1) Load levels; (2) transmission planned and contingency outages; (3) generation planned and contingency outages; (4) base generation dispatch; (5) existing transmission reservations, including counterflows; (6) ATC recalculation frequency and times; and (7) source/sink modeling identification. The Commission concludes that the exchange of such data is necessary to support the reforms requiring consistency in the determination of ATC adopted in this Final Rule. As explained above, transmission providers are required to coordinate the calculation of TTC/TFC and ATC/AFC with others and this requires a standard means of exchanging data.

311. While there is a near consensus among commenters that significant improvements in the communication, coordination, and exchange of data across all transmission providers are needed to produce accurate determinations of ATC, we acknowledge the concerns of ISO/RTOs that new data exchange protocols may interfere with the existing protocols and seams coordination agreements. Although we will not provide a blanket exemption for ISOs and RTOs from meeting or exceeding the data exchange requirements of this Final Rule, they may, as explained in section IV.C.2, demonstrate in relevant filings that their existing data exchange protocols are consistent with or superior to those that are developed in the NERC and NAESB processes.[191]

312. With respect to concerns regarding the exchange of data that may be a subject of confidentiality and commercially sensitive, we only require information necessary for purposes of ATC modeling to be exchanged. As suggested by some commenters, proprietary generation or market information data that might harm a competitive position should not be publicly disseminated, since that would not enhance the ability of transmission providers to accurately calculate ATC. If any of the data are subject to confidentiality and are commercially sensitive, they must be disclosed in accordance with a confidentiality agreement.

2. Transparency

a. OATT Transparency

(1) Attachment C

NOPR Proposal

313. In the NOPR, the Commission proposed to require each transmission provider to include in Attachment C of its OATT more descriptive information concerning its ATC/AFC calculation methodology. Specifically, the Commission proposed to require the transmission provider to state its specific mathematical algorithm used to calculate firm and non-firm ATC/AFC for its scheduling horizon, operating horizon, and planning horizon. The Commission also proposed to require transmission providers to provide a process flow diagram that illustrates the various steps through which ATC/AFC is calculated. In addition, the Commission proposed to require transmission providers to provide definitions and explain in detail how TTC, ETC, AFC, TRM, and CBM are calculated for both operating and planning horizons.

Comments

314. Most commenters support the Commission's overall proposal on transparency in ATC calculations.[192] Numerous commenters support the Commission's proposal to require detailed information in Attachment C regarding the transmission provider's ATC/AFC calculation methodology.[193] Barrick agrees in its reply comments that a thorough explanation of how ATC is calculated should be made readily available either in the transmission provider's OATT or on its OASIS, thereby improving transparency and making it less difficult for customers to determine whether the calculations are unduly discriminatory. Old Dominion calls for greater transparency in the details of calculating ATC, even as applied to RTOs such as PJM because of the relevance of ATC at the borders of an RTO/ISO and the market impact of inconsistencies in definitions, data, modeling assumptions and frequency of ATC calculations. NERC states that the revised NERC reliability standards will address transparency.

315. NARUC contends that understanding ATC calculation methodologies and having access to the underlying data is essential to a range of critical State commission functions and, therefore, greater transparency of ATC information will significantly enhance State commissions' abilities to fulfill their statutory obligations. On reply, North Carolina Agencies agree with NARUC and state that efforts aimed at increased transparency of ATC calculations should help uncover any actual discriminatory behavior by transmission providers, provide a clearer standard against which to evaluate claims of unduly discriminatory activities, and facilitate regional planning efforts. Entegra states on reply that transmission providers should be required to post narratives explaining changes in models and factors underlying ATC and AFC values, which would be invaluable to the Commission and customers in identifying problems that may warrant enforcement actions.

316. While APPA generally supports the Commission's proposal, some of APPA's members along with other commenters express concern that including all the information might be too burdensome and result in numerous tariff changes.[194] Some APPA members in the West also express concerns about the competitive implications of

[191] We are not requiring that every transmission provider follow identical protocols. Rather, all transmission providers must meet the relevant NERC reliability standards and NAESB business practices, and each entity will be subject to reliability standards compliance audits through which they will have to demonstrate that they meet or exceed the reliability standards.

[192] *E.g.*, Alberta Intervenors, AWEA, Bonneville, CAISO, Constellation, Duke, East Texas Cooperatives, ELCON, Entergy, Entegra, EPSA, E.ON, Exelon, MidAmerican, Morgan Stanley, Municipals, Nevada Companies, NPPD, PGP, PJM, Powerex, CREPC, Santee Cooper, TVA, TAPS, and TDU Systems.

[193] *E.g.*, Arkansas Municipal, Arkansas Commission, CAISO, Constellation, ELCON, Entergy, ISO New England, Morgan Stanley, NARUC, Nevada Companies, Occidental, PJM, Powerex, Project for Sustainable FERC Energy Policy, Santee Cooper, and Suez Energy NA.

[194] *E.g.*, EEI, PNM–TNMP, Sacramento, Seattle, and Southern.

providing such confidential and sensitive information.

317. EEI also notes that providing additional detailed information in Attachment C would be duplicative and may result in confusion due to inconsistencies between the wording of the NERC and NAESB ATC documents and each transmission provider's Attachment C. To avoid uncertainty, EEI recommends that the Commission require transmission providers to comply with the requirements of Attachment C by referencing NERC reliability standards or business practices that provide the information that is called for in the Attachment. MidAmerican believes that additional information concerning calculating ATC and its components would best be retained in the transmission provider's business practices rather than Attachment C. In its reply comments, Powerex suggests an alternative of permitting transmission providers to provide a general reference to NERC, WECC, or NAESB standards and fully outline core definitions, processes, data and assumptions when deviating from such standards.

318. Southern contends that the transparency concerns expressed in the NOPR are driven more by the complexity and volume of the data involved rather than a lack of information. Southern suggests that sufficient information is readily available and the best course of action by the Commission would be to focus on documenting transfer capability methodologies available to transmission customers. NRECA replies that many commenters provided input into why more transparency is needed and repeats the example provided in its NOI comments of a cooperative that spent many months in discussions with a public utility transmission provider in an effort to understand ATC-related information posted on OASIS.

319. Pinnacle contends that the Commission's proposal for detailed information in Attachment C is only relevant in flow-based systems, pointing out that in the Western Interconnection, the scheduling horizon, and the operating horizon are the same and thus reporting such information is not necessary. APPA and Bonneville believe that adding such detail in Attachment C may only result in incremental changes and suggest that better regional coordination would provide greater transparency.

320. Though ISO New England believes this proposal would not create an undue burden, it urges the Commission to allow for variety in the illustration of the process flow diagram. Regarding the proposal to require a ''detailed explanation'' of the calculation of ATC, TTC, ETC, and TRM components, ISO New England argues that the relevant inputs can change on a daily basis because ATC for Pooled Transmission Facilities (PTF) in New England is a function of market conditions, as opposed to an administratively-derived calculation. In ISO New England's view, the level of detail required should reflect the operation of competitive markets. MISO is concerned that the NOPR does not address transparency and regional coordination issues arising at the seams between market and non-market areas, particularly with respect to ATC calculations.

321. MidAmerican strongly urges the Commission to ensure that non-public utility transmission providers adhere to the transparency requirements, since in the Pacific Northwest many of the ''backbone'' transmission lines are co-owned by jurisdictional and nonjurisdictional entities. A jurisdictional co-owner may be limited in its ability to determine such parameters as TRM and CBM because it may not be the line operator. LPPC, in its reply comments, believes it is unnecessary and redundant to require non-public utility transmission providers to adopt the ATC requirements of the *pro forma* OATT, because the Commission recognizes in the NOPR that NERC and NAESB are currently drafting standards for ATC, which when final will be filed with the Commission and become part of the ERO's mandatory reliability standards and fully applicable to otherwise nonjurisdictional entities.

322. Suez Energy NA contends that it is essential that the Commission include an explanation of each component of the ATC calculation in Attachment C to ensure that the transmission provider incorporates NERC standards appropriately and to ensure proper enforcement in the event that an audit shows that the transmission provider has employed other methods of calculating ATC. Suez Energy NA also notes that the mathematical algorithms and process flow diagrams should be provided to users of the transmission system, independent monitors, transmission coordinators and regulators, even if a confidentiality agreement is required. APPA suggests that the Commission and regional reliability organizations conduct additional audits to ensure that these posted practices and procedures are in fact being followed, and that the data used are verifiable.

Commission Determination

323. The Commission adopts the NOPR proposal to increase transparency regarding ATC calculations by requiring each transmission provider to set forth its ATC calculation methodology in its OATT. Each transmission provider must, at a minimum, include the following information in Attachment C to its OATT. It must clearly identify which of the NERC-approved methodologies it employs (*e.g.*, contract path, network ATC, or network AFC). It also must provide a detailed description of the specific mathematical algorithm the transmission provider uses to calculate firm and non-firm ATC for the scheduling horizon (same day and real-time), operating horizon (day ahead and pre-schedule), and planning horizon (beyond the operating horizon). In addition, transmission providers must include a process flow diagram that describes the various steps that it takes in performing the ATC calculation. Furthermore, transmission providers must set forth a definition of each ATC component (*i.e.*, TTC, ETC, TRM, and CBM) and a detailed explanation of how each one is derived in both the operating and planning horizons. Requiring transmission providers to file a statement of their ATC calculation methodology along with a process flow diagram and more detailed definitions of ATC components in Attachment C of the OATT will provide greater transparency to transmission customers and assist in identifying any discrepancies that may arise in ATC determinations. These new requirements will assist in alleviating any appearance of discrimination in the determination of ATC.

324. The Commission acknowledges NARUC's comments that understanding ATC methodologies and the underlying data also will enhance State regulators' ability to meet their regulatory obligations. More transparent ATC calculations are critical to coordinated regional transmission planning that ultimately will improve transmission access for customers and enhance grid reliability. Transparent ATC calculations facilitate the ability of market participants and regulators to detect discrimination.

325. We do not believe our requirement to include additional information in Attachment C will be overly burdensome or lead to an excessive level of future tariff revisions. Attachment C must provide an accurate documentation of processes and procedures related to the calculation of ATC, not the actual mathematical algorithms themselves, which should be

posted on the transmission provider's Web site. These processes define service availability and, as such, must be part of the transmission provider's OATT. It is entirely appropriate that, because revisions to such processes impact transmission availability, they should be filed for Commission approval and included in a transmission provider's OATT. We also require transmission providers to file a revised Attachment C to incorporate any changes in NERC's and NAESB's revised reliability standards and business practices related to ATC calculations, as requested by the Commission in this Final Rule. This filing should be made within 60 days of completion of the NERC and NAESB processes. As we expect transmission providers to rarely change their ATC calculation methodologies, we do not believe this requirement will trigger an unacceptable level of tariff filings modifying the Attachment C description of the ATC components and processes.

326. We agree with ISO New England that the process flow diagram requirement may be met with a variety of illustrations, so long as it is of sufficient detail to provide the transmission customer with a reasonable understanding of the transmission provider's ATC calculation processes. The process flow diagram should support the other Attachment C requirements. As noted above, we agree with Suez Energy NA that mathematical algorithms and process flow diagrams should be made available. We do not find that a confidentiality agreement is generically warranted; however, we note that, a transmission provider may require a confidentiality agreement for CEII materials, consistent with our CEII requirements, or may otherwise protect the confidentiality of proprietary customer information.

327. We also require transmission providers to document their processes for coordinating ATC calculations with their neighboring systems. This requirement is particularly important with respect to seams between market and non-market areas, as identified by MISO, and with respect to the request of other commenters to increase regional coordination regarding ATC calculation. While this Final Rule does not address all seams issues between market and non-market areas, it does take important steps towards that end by improving data exchange between transmission providers and providing increased transparency with respect to ATC calculation.

328. We reject proposals to address the transparency of ATC methodology by merely referencing business practices and reliability standards developed by NERC, NAESB, and WECC.[195] ATC calculations have a direct and tangible effect on the granting of open access transmission service.[196] As such, an accurate and detailed statement of the methodology and its components that defines how the transmission provider determines ATC belongs in the transmission provider's OATT as the means of holding the transmission provider accountable for following non-discriminatory procedures for granting service, not in business practices kept by the transmission provider.[197] However, as noted above, the actual mathematical algorithms should be posted on the transmission provider's web site, with the link noted in the transmission provider's Attachment C.

329. We also reject Pinnacle's assertion that more detailed information in Attachment C would only apply to flow-based systems. Regardless of what type of ATC calculation methodology is employed, transparency in ATC calculations is critical to avoid undue discrimination when allocating transmission capacity under the *pro forma* OATT.

330. In response to MidAmerican's comments regarding the applicability of the ATC-related reforms to non-public utilities, we again refer to section IV.C.3 where we discuss this issue generally. We note here, however, that the ERO's reliability standards currently in development before the Commission will be applicable to all users, owners and operators of the bulk electric grid, which includes non-public utilities.

331. We do not believe ATC-specific tariff audits are necessary to order at this time. The Commission will continue to provide oversight of all tariff-related activities through its enforcement program. Moreover, ATC requirements will be part of the mandatory and enforceable reliability standards and, as such, will be subject to compliance audits through that process.

[195] WECC has on file a Reliability Management System agreement under which transmission providers agreed, through contracts, to follow WSCC reliability criteria. *Western Systems Coordinating Council*, 87 FERC ¶ 61,060 (1999).

[196] The Commission recognized in Order No. 889 that the methodology for calculating ATC and TTC belongs in the tariff. Order No. 889 at 31,607. At the time, the industry represented that it was engaged in efforts to develop uniform methods of determining ATC. The Commission encouraged such industry efforts and required that the tariff include the methodology, which was to be based on current industry practices, standards and criteria.

[197] For the same reason, the Commission disagrees with the assertions of Southern and EEI that more information in Attachment C would be duplicative because some ATC-related information is already available elsewhere.

(2) CBM Practices

NOPR Proposal

332. In the CBM Order, the Commission required transmission providers to post a specific narrative explanation of their CBM practices.[198] In addition, the Commission directed transmission providers to post their procedures for allowing access to CBM during emergencies. The Commission further stated in the CBM Order that, if a utility's practice was not to set aside transfer capability as CBM, it should reflect that in Attachment C.

333. In the NOPR, the Commission proposed to require transmission providers to include this CBM narrative in Attachment C of their OATTs. In addition, the Commission proposed that transmission providers explain their definition of CBM, list the databases used in their CBM calculations, and prove that there is no double-counting of contingency outages when performing CBM calculations.

Comments

334. Seattle and Suez Energy NA support this proposal. Seattle states that CBM information should be specified in Attachment C in order to provide clear guidance for the specific information that is posted on OASIS. Seattle and APPA suggest that CBM should be verifiable and subject to audit by independent parties such as regional reliability organizations.

335. EEI suggests that the Commission revise Attachment C, section 3(f) to replace the word ''prove'' with the word ''demonstrate'' in the requirement that the transmission provider ''prove'' that it does not double count contingency outages when calculating CBM, TTC and TRM. EEI notes that the term ''prove'' implies a determination on the merits after evaluation of competing arguments and evidence. A transmission provider should be able to satisfy its obligations by ''demonstrating'' the absence of a double count. Any customer that wishes to challenge the demonstration can do so, at which time the issue of ''proof'' would arise.

336. With regards to ''double counting,'' TVA references TRM and agrees that additional explanations regarding the calculation of TRM, including methods used to avoid double counting contingency events, should improve transparency in providing open access transmission service. TVA points out that this is being addressed by a NERC standards drafting team.

[198] *Capacity Benefit Margin in Computing Available Transmission Capacity*, 88 FERC ¶ 61,099 (1999) (CBM Order).

Commission Determination

337. The Commission adopts the NOPR proposal requiring additional information in the transmission provider's OATT Attachment C regarding its determination of CBM. Transmission providers must provide in Attachment C a narrative description detailing their CBM practices. In addition, a transmission provider must explain its definition of CBM and list the databases used to derive its value. These new requirements will provide transmission customers transparency into the CBM component of ATC and help discourage the potential for undue discrimination in the calculation and use of CBM.

338. We adopt EEI's proposal that the Commission revise Attachment C, section 3(f) to replace the word ''prove'' with the word ''demonstrate.'' The word ''demonstrate'' more accurately describes the showing we expect the transmission provider to make. We agree that the word ''prove'' implies a standard of proof that we did not intend to impose. We also acknowledge TVA's comments that the NERC standards drafting team is developing standards that should address ''double counting'' in ATC calculations in general. However, we require that the information in Attachment C be sufficient to demonstrate that a transmission provider is not double counting CBM in its ATC calculation.

339. Finally, the Commission rejects the proposal by Suez Energy NA, APPA, and Seattle to establish formal audits of CBM set asides. Requirements for CBM will be part of the mandatory and enforceable reliability standards and, as such, will be subject to compliance audits through that process. Moreover, the Commission provides oversight of all tariff-related activities through its enforcement program.

b. OASIS

(1) ATC/TTC Posting Requirements

NOPR Proposal

340. The Commission's existing regulations require certain ATC-related information to be posted on each transmission provider's OASIS and other information to be provided on request. To ensure that relevant information is available on a timely basis to all market participants, the Commission proposed in the NOPR to amend its regulations to allow potential customers greater access to information that will enable them to obtain service on a non-discriminatory basis from any transmission provider.

341. The Commission noted in the NOPR that existing regulations require ATC and TTC calculations to be performed according to consistently applied methodologies referenced in the transmission provider's OATT and current industry practices, standards and criteria. The Commission proposed that these calculations be based on the ERO reliability standards.

342. The Commission further proposed to maintain the requirement that transmission providers provide, on request, all data used to calculate ATC and TTC for any constrained paths. Transmission providers also would remain required, on request, to make publicly available any system planning studies or specific network impact studies performed for customers and to post a list of such studies on OASIS.

Comments

343. Several commenters support the proposal to post ATC-related information on OASIS.[199] TDU Systems supports each of the Commission's proposals with respect to providing easier access to data underlying ATC calculations and greater transparency to the process. Sacramento states that posting on OASIS will ensure proper public access, but will avoid the need for Commission approval of an OATT change.

344. Constellation strongly supports the need for additional transparency, stating that providing transmission customers with meaningful insight into the current ''black box'' determination of ATC will help minimize the mystery underlying many transmission provider responses to service requests. According to Constellation, further transparency will assist customers in predicting the outcome of transmission service requests and facilitate increased commercial activity. Constellation suggests that the Commission require transmission providers to provide transmission customers, on request, with specific details related to modeling data, modeling support information, modeling benchmarking and forecasting data, and transmission service request audit data. It requests that the information be in a form and format usable by the transmission customers and that the Commission take steps to ensure that transmission customers understand how ATC is calculated and the data inputs are used to affect those calculations.

345. Great Northern likewise requests that the Commission enhance the requirement to provide all data on request, specifically on constrained paths, by requiring a posted tabulation of annual and monthly ATC calculation details. Great Northern suggests including TTC, network load for each transmission customer, capacity reserved for each network resource, each point-to-point transmission service reservation, CBM and other deductions from TTC.

346. APPA members support the posting of ATC information, as it will assist in using ATC more efficiently, and they support the posting of system planning studies and specific network impact studies that the transmission provider performs for its own merchant function, as well as studies performed for customers. In addition, APPA suggests the posting of facilities studies at the time they become available, assuming that this can be done consistent with CEII concerns. TAPS goes further by urging the Commission to close gaps in the current OASIS requirements by requiring posting of all studies performed for transmission owners' own transmission network resource designations and other uses of the system, including facilities studies as well as system impact studies, ensuring posted study lists are updated contemporaneously with the availability of new studies, and requiring retention of studies for a minimum of five years.

347. Nevada Companies and TVA support cost effective measures that increase transparency in transmission operations and, unless the requirement becomes unduly time consuming or burdensome, in general support more disclosure rather than less.

Commission Determination

348. The Commission adopts the proposal in the NOPR to continue to require transmission providers to comply with existing ATC-related posting obligations as supplemented by this Final Rule. The Commission will continue to require transmission providers, on request, to make available all data used to calculate ATC and TTC for any constrained paths and any system planning studies or specific network impact studies performed for customers. Transmission providers must also continue to post a list of such studies on OASIS.

349. In addition, we agree with the requests of APPA and TAPS to require the additional posting of, at a minimum, a listing of all system impact studies, facilities studies, and studies performed for the transmission provider's own network resources and affiliated transmission customers, to be made available upon request. We note that appropriate procedures to accommodate CEII concerns should be developed to

[199] *E.g.*, APPA, Constellation, FirstEnergy, Indianapolis Power, Sacramento, Suez Energy NA, TAPS, and TDU Systems.

ensure eligible entities with a legitimate interest in transmission study data can receive access to it. Also, we adopt TAPS' suggestion that the studies be made available for five years to make the requirement consistent with data retention requirements pertaining to denial of service requests.

350. The Commission rejects Constellation's and Great Northern's proposals to require transmission providers to provide upon request or regularly post additional information beyond that required in the regulations and this Final Rule. The transmission provider is already required to make available, upon request and in electronic format, all information related to the calculation of ATC and TTC for any constrained path. Accordingly, we see little benefit to require transmission providers to provide upon request or regularly post additional information suggested by these commenters.

(2) CBM/TRM Posting Requirements

NOPR Proposal

351. The Commission's OASIS regulations currently require transmission providers to calculate and post ATC and TTC for each posted path, but make no requirement for CBM and TRM postings. In the CBM Order, however, the Commission required transmission providers, with respect to each path for which the utility already posts ATC, to post (and update) the CBM figure for that path. The Commission also required transmission providers to make any transfer capability set aside for CBM available on a non-firm basis and to post this availability on OASIS. In the NOPR, the Commission proposed to incorporate these CBM posting requirements into its regulations. The Commission also proposed that transmission providers post (and update) the TRM values for the paths on which the transmission provider already posts ATC, TTC, and CBM.

Comments

352. Several commenters strongly support the Commission's proposal to require transmission providers to post TRM and CBM.[200] APPA and EPSA agree that the posting of TRM for near term transmission services would provide greater assurance that ATC calculations are being performed according to established procedures. Since transmission providers already have this information, FirstEnergy states that it does not appear to be unduly burdensome for them to post such information. Bonneville indicates that it currently posts TRM values in its Business Practices Forum, which is useful for examining curtailment events, supporting transmission planning objectives, and validating posted ATC values.

353. EPSA also recommends that the Commission provide guidance on standards that should be developed to require each transmission provider to notify the Commission in writing and post a notice on its OASIS within 24 hours of a transmission provider's use of CBM to import emergency power. EPSA also requests that the amount of CBM reserved for each interface be posted on OASIS.

Commission Determination

354. The Commission adopts the CBM posting requirements proposed in the NOPR. In doing so, we amend our OASIS regulations to incorporate the directives established in the CBM Order. Accordingly, we require transmission providers to post (and update) the CBM amount for each path. In addition, the Commission requires transmission providers to make any transfer capability set aside for CBM but unused for such purpose available on a non-firm basis and to post this availability on OASIS. Furthermore, the Commission requires transmission providers to post (and update) the TRM values for the paths on which the transmission provider already posts ATC, TTC, and CBM.

355. We reject EPSA's request to require transmission providers to notify the Commission in writing and post a notice on OASIS within 24 hours of a transmission provider's use of CBM to import emergency power and transfer capability set aside as CBM at each of the transmission provider's interfaces. The additional transparency of CBM-related information provided in this Final Rule, along with the reforms related to consistency of CBM, will cause sufficient information to be made available to customers concerning the use of CBM. The use and allocation of CBM and TRM will be more transparent to transmission customers, thus reducing the potential for undue discrimination.

(3) Periodic Reevaluation of the CBM Set-Aside

NOPR Proposal

356. In the CBM Order, the Commission stated that the level of ATC set aside for CBM can and should be reevaluated periodically to take into account more certain information (such as assumptions that may not have, in fact, materialized).[201] The Commission therefore directed transmission providers to periodically reevaluate their generation reliability needs so as to make known the availability of CBM and to post on OASIS their practices in this regard.[202] In the NOPR, the Commission proposed to incorporate these requirements in the Commission's regulations and to obligate transmission providers to reevaluate the CBM set-aside at least quarterly.

Comments

357. Some commenters support quarterly reevaluation of CBM set-asides.[203] TAPS agrees with the need for full transparency of CBM reservations and practices and states that, because CBM values may differ from season to season, CBM values should be separately calculated for at least each quarter. However, TAPS does not find that it is necessary or appropriate for the CBM values to be reevaluated quarterly, given the effort involved in collecting the data and performing the modeling analysis. Rather, CBM studies should be performed at least every other year, supplemented with ''off-year studies'' when appropriate.

Commission Determination

358. The Commission incorporates into its regulations the requirement in the CBM Order for a transmission provider to periodically reevaluate its transfer capability set-aside for CBM. With respect to TAPS' concerns over the effort involved in the re-evaluation process, we will require CBM studies to be performed at least every year. This requirement is consistent with the CBM Order, in which the Commission stated that the level of ATC set aside for CBM should be reevaluated periodically to take into account more certain information (such as assumptions that may not have, in fact, materialized).[204] While changes requiring a reevaluation of CBM are longer-term in nature (*e.g.*, installation of a new generator or a long-term outage), quarterly may be too frequent, though two years may be too long and may prevent a portion of the CBM set-aside from being released as ATC. Moreover, annual reevaluation is consistent with the current NERC standard being developed in MOD–005.[205] The requirement to evaluate CBM at least every year also is consistent with the CBM Order in that

[200] *E.g.,* Powerex, PJM, PPL, Seattle, and Pinnacle.

[201] *CBM Order* at 61,237.

[202] *Id.*

[203] *E.g.,* EPSA, Sacremento, Santa Clara, Suez Energy NA, and TDU Systems.

[204] CBM Order at 61,237.

[205] The MOD–005 reliability standard establishes the procedure for verifying CBM values.

the Commission directed transmission providers to periodically reevaluate their generation reliability needs so as to make known the need for CBM and to post on OASIS their practices in this regard.

(4) ATC/TTC Narrative Explanation

NOPR Proposal

359. In the NOPR, the Commission proposed to largely retain existing posting requirements for unconstrained posted paths, but to amend the regulations relating to data posted for constrained posted paths. Existing regulations require ATC and TTC on constrained paths to be updated when (1) Transactions are reserved, (2) service ends, or (3) whenever the TTC estimate for the path changes by more than 10 percent.[206] In the NOPR, the Commission proposed to supplement the existing regulations by requiring the transmission provider to post a brief, but specific, narrative explanation of the reason for the change at the time a change in monthly and yearly ATC values on a constrained path is posted. The Commission sought comment on whether the posting of this new information would provide adequate transparency to the customer on a frequent enough basis without imposing an undue burden on the transmission provider. The Commission also sought comment on whether a similar narrative should be required when ATC remains unchanged at a value of zero for some specified period of time.

Comments

360. Some commenters support the Commission's proposal to require transmission providers to post more detailed explanations about changes in ATC values on their OASIS sites.[207] NAESB, TranServ, and Williams request that the Commission clarify the regulatory requirements for posting of updated ATC values such as the level of standardization, frequency and time of postings, and other requirements. CAISO believes that ATC should be updated on a daily basis.

361. Powerex and Nevada Companies propose that additional disclosures be posted, such as data on grandfathered contracts, time-specific data relevant to transmission constraints and ATC rights on posted paths, and remaining customer rights under a reservation-based network service system.

362. A few commenters caution that some of the data that the Commission is requiring to be posted by transmission providers is market-sensitive and, if posted on a real-time basis, could be used by third parties to obtain an unfair competitive advantage.[208] These commenters propose that the transmission providers should be allowed a brief period of delay (*e.g.*, one week) before posting data. Indianapolis Power also advocates a delay due to the burden on transmission providers of the new posting.

363. Several commenters oppose the Commission's proposal to require that transmission providers post narratives on OASIS outlining reasons why monthly and yearly ATC values on constrained paths change.[209] These commenters contend that this will cause undue burden on transmission providers without providing customers with any significant or new information. They also argue that the proposal is impractical and will not result in providing transmission customers with meaningful information regarding transmission service options.

364. If such a requirement is adopted, MISO recommends that a threshold higher than a 10 percent change in ATC be established and that the Commission clarify what the term ''specific explanation'' means in this context. PJM states that it already exceeds the Commission's proposed requirement. However, if strictly applied, this proposal would be unduly burdensome on PJM because it would require PJM to post a narrative each hour. PJM asks that the Commission not apply unnecessary and costly posting requirements on independent RTOs and ISOs.

365. EEI and Southern are concerned that monthly ATC may change in response to every reservation of hourly transmission service because a reservation of hourly firm service on a constrained path may reduce the availability of monthly firm service. EEI contends that, if transmission providers are required to post changes in TTC instead of ATC, they would not be required to post a new narrative every time a reservation is made, thus reducing the overall burden on transmission providers. EEI additionally states that the reasons for changes in TTC and ATC values often are complex and involve the interaction of multiple variables in the model that produces the TTC and ATC values and a specific change in TTC or ATC cannot easily be traced to a specific change in the inputs. Alternatively, EEI suggests that transmission providers could post the major changes in the inputs to the TTC modeling software that are made in connection with each updated TTC posting without ascribing specific inputs to specific changes in TTC and ATC values on specific lines.

366. Several commenters are supportive of the proposed requirement that transmission providers provide a narrative explanation when ATC values remain at zero.[210] APPA suggests that if a particular interface shows an ATC of zero for a specified period, the transmission provider should provide a narrative explanation of why this is the case and how its plans to address this problem. It also suggests that this information should be employed in the transmission planning process. East Texas Cooperatives, in reply comments, state that the narrative can provide useful information to the transmission customers and State and Federal regulators regarding specific conditions regarding ATC coordination.

367. In supplemental comments, NAESB states that the Commission should specify whether it is sufficient for the explanation of changes in ATC or TTC values to be limited to broad generalized statements or whether the posted information should include such information as the specific events which gave rise to the change, the new values for ATC at all points on the network, the impact of the change on transmission customers, and a detailed snapshot of the conditions on the system at all flowgates or constrained elements when the change occurred.[211]

368. Southern states that posting a narrative when ATC remains at zero is unwarranted and unnecessary, as it simply indicates that the market has responded to market signals of ATC availability and purchased all available capacity.

Commission Determination

369. The Commission adopts the NOPR proposal, with the modifications discussed below, to require that the transmission provider post a brief, but specific, narrative explanation of the reason for a change in monthly and yearly ATC values on a constrained path. Rather than requiring a narrative

[206] *See* 18 CFR 37.6(b)(3)(i)(C).

[207] *E.g.,* Arkansas Commission, CAISO, Constellation, East Texas Cooperatives, Exelon, FirstEnergy, LPPC, Morgan Stanley, NRECA, Pinnacle, Powerex, Santa Clara, and Suez Energy NA.

[208] *E.g.,* Ameren, ISO New England, Southern, and NRECA.

[209] *E.g.,* Ameren, EEI, Entergy, MISO, Pinnacle, PJM, PNM–TNMP, Southern, TranServ, and TVA.

[210] *E.g.,* APPA, East Texas Cooperatives, Suez Energy NA, and TAPS.

[211] November 2, 2006, *Addendum to the Testimony of Ronald M. Mucci on behalf of the North American Energy Standards Board,* Preventing Undue Discrimination and Preference in Transmission Service, Docket Nos. RM05–25–000 and RM05–17–000, October 12 Technical Conference, pp. 2–3.

when a monthly or yearly ATC value changes as a result of transactions being reserved, service ending, or the TTC estimate for the path changing by more than 10 percent, we will require a narrative when a monthly or yearly ATC value changes only as a result of a 10 percent change in TTC. This will reduce the number of ATC changes for which a narrative will be required and address concerns that the new requirement unduly burdens transmission providers. Any remaining burden is justified by the benefit to transmission customers of receiving timely information regarding changes in TTC that result in changes to ATC. In addition, we adopt NAESB's suggestion that posted information include the (1) Specific events which gave rise to the change and (2) new values for ATC on that path (as opposed to all points on the network).

370. We reject calls for delays prior to posting data. While commenters allege the possibility of granting others a competitive advantage through the release of ''market-sensitive'' data, they have proffered no evidence to support the allegation of potential harm.

371. We do require, as suggested in the NOPR, a narrative with regard to monthly or yearly ATC values when ATC remains unchanged at a value of zero for a significant period, and will set that period at six months or longer. This information will be valuable to customers and regulators in assessing the ability of a transmission provider's facilities to meet existing service requests. The information also will provide assurance to customers that the transmission provider is diligent in regularly evaluating ATC on all paths, monitoring persistent constraints and addressing them in its planning processes.

372. Finally, we reject CAISO's suggestion that ATC be updated daily on a transmission provider's OASIS site, because CAISO offered no justification for the proposal.

(5) Denial of Service/Records Retention

NOPR Proposal

373. In the NOPR, the Commission proposed to maintain the requirement that a transmission provider post the reason for a denial of a request for service. The Commission also proposed to amend this provision to require a transmission provider to maintain and make available information supporting the reason for the denial. The Commission further proposed to extend the time period for which transmission providers must maintain transmission service information for audit. Currently, regulations require that audit data be retained and made available upon request for download for three years from the date when they are first posted. The Commission proposed to change the period from three to five years.

Comments

374. Many commenters support posting of the reasons for denying service and the 5-year retention proposal.[212] TAPS supports the proposal but suggests several modifications. First, it suggests that the Commission clarify the requirement to post the reasons for denying service is triggered not only by denial of the entirety of a transmission request, but to any disposition that falls short of a full unconditional grant of the service (with rollover rights if applicable). Second, TAPS recommends that the regulatory text of proposed section 37.6(e)(2)(ii) be modified to make the supporting data available, upon request, to any eligible customer rather than just to the customers who were denied service. Third, it asks that the Commission expand its OASIS regulations to require the transmission provider to maintain and make available on request the information supporting the disposition (positive, negative, or in between) of its own network resource designations and other usage needs. East Texas Cooperatives suggest that the Commission also require that transmission providers distinguish between denials of requests for firm and non-firm transmission service.

375. Some commenters urge the Commission to clearly define the scope of any transmission service request information subject to the proposed five-year record retention requirement to ensure that no undue administrative burden is placed on transmission providers.[213] TVA questions the need to extend the time period for an additional two years. TVA states that the benefits of extension are not commensurate with the increased costs, since it is unaware of any problems that have arisen with the current three-year timeline. Seattle argues on reply that the Commission should retain the NOPR posting requirements in the Final Rule because information on actual transmission congestion can be helpful instead of sole reliance on simulation models.

[212] *E.g.,* APPA, Arkansas Commission, Arkansas Municipal, Duke, East Texas Cooperatives, MISO, ISO New England, Williams, Nevada Companies, PPL, Sacremento, Sant Clara, Suez Energy NA, and TDU Systems.

[213] *E.g.,* MidAmerican, PacifiCorp, PNM–TNMP, and PJM.

Commission Determination

376. As proposed in the NOPR, the Commission maintains the requirement that a transmission provider post the reason for a denial of service and extends from three years to five years the period for which transmission providers must maintain data providing reasons for denial of service. In general, commenters support the requirement for posting denial of service information and the increase in retention time to five years, indicating that such information can be helpful to customers in their awareness of actual transmission congestion, rather than relying on simulation models.

377. We also adopt TAPS' suggestion to expand the regulations to include availability of information supporting the disposition of a transmission provider's own network resource designations and to make such information available to any eligible customer rather than just to that customer denied service. In addition, we clarify that a partial denial of service triggers the requirements as well. Such information is consistent with the new regulations established by this Final Rule and will help ensure that customers receive transmission service that is not unduly discriminatory. The development of a log of service denials, full or partial, will establish an ongoing record of service requests and transmission provider responses demonstrating the transmission provider's provision of nondiscriminatory open access service. Furthermore, repeated denials of service over a particular path or flowgate will provide an indication of congestion that can be used in the transmission planning process. In addition, we agree with East Texas Cooperatives that postings of denials of service should indicate whether the requested service was firm or non-firm.

(6) Designation and Termination of Network Resources

NOPR Proposal

378. In the NOPR, the Commission proposed to require the transmission provider and network customers to use the transmission provider's OASIS to request designation of a new network resource and to terminate the designation of a network resource. This information would be posted on OASIS for 90 days and be available for audit for a five-year period. Transmission customers therefore would be able to query such requests to designate and

terminate a network resource.[214] The Commission also proposed to require the transmission provider to post on its OASIS a list of its current designated network resources and all network customers' current designated network resources. The list would include the resource name, geographic and electrical location and amount of capacity of the designated network resource.

Comments

379. Several commenters support the Commission's proposal to require transmission providers and network customers to use the transmission provider's OASIS to request or terminate designation of resources, though some indicated that the required network resource information is currently available via OASIS.[215] PJM supports the proposal, provided that the electrical location is based on an industry standard format and any standard adopted by NERC takes into consideration possible confidentiality issues when posting the geographic location of designated network resources.

380. APPA suggests that reservations related to future load growth also should be posted so that it is clear to all industry participants what transmission capacity transmission providers are reserving for load growth purposes. Williams submits that the list of current designated resources needs to indicate whether they are for native load or network customers, or whether they are for meeting forecasted loads and system emergencies.

381. TranServ supports the Commission's proposal and indicates that NAESB is the appropriate forum for development of standards necessary to support posting the designation and termination of network resources. TranServ cautions that implementation will require a sufficient period of time after the practices and standards are developed and suggests that changes to OASIS should be timed to avoid peak summer and winter seasons.

382. Exelon requests that the Commission clarify that transmission providers and network customers making firm off-system sales may terminate designation of network resources solely for the term of such sale and not for other periods of time. During this period of termination, the firm capacity is posted and made available to other customers.

[214] *See* 18 CFR 37.6(a)(6).

[215] *E.g.*, APPA, Exelon, PJM, TAPS, TranServ, and TDU Systems.

383. Great Northern supports the proposal and requests clarification that, when a network resource is ''undesignated,'' ATC will not be set aside in anticipation that it might be designated again as a network resource in the future. Great Northern requests that the Commission confirm that new requests to designate network resources, regardless of the prior designation of those resources, are placed at the end of the transmission service queue.

384. Sacramento states that the posting requirements for network resources are an unnecessary burden and instead recommends that the transmission provider should be required to identify resources it is transmitting to native load when it denies a request for transmission service from a third party.

Commission Determination

385. The Commission adopts the NOPR proposal and requires transmission providers and network customers to use OASIS to request designation of new network resources and to terminate designation of network resources.[216] This information shall be posted on OASIS for 90 days and available for audit for a five-year period. Transmission customers thus shall be able to query requests to designate and terminate a network resource. This requirement adds valuable transparency without undue burden, since it is nothing more than maintaining a database of designation requests made and responded to electronically. The Commission orders public utilities, working through NAESB, to develop appropriate templates for OASIS.

386. The requests for clarifications by Exelon and Great Northern will not be addressed in this section. These requests are not related to OASIS postings, but involve changes in tariff language. They are addressed in section V.D.6 of this Final Rule.

(7) Posting of Unused Transfer Capability

NOPR Proposal

387. In the NOPR, the Commission reminded transmission providers that transfer capability associated with transmission reservations that is not scheduled in real time should be included in non-firm ATC and posted on OASIS.

Comments

388. Entegra, TANC, and TDU Systems emphasize the need for the posting of unused transfer capability. TDU Systems state that the requirement to post on OASIS all transfer capability associated with transmission reservations not scheduled in real time furthers not only the Commission's goals with respect to comparability and transparency of ATC calculations, but also the Commission's goals in freeing up access to transmission capacity for transmission customers.

[216] *See* paragraph 1477, where further detail on using OASIS to request designation of network resources is provided.

Commission Determination

389. We affirm our statement in the NOPR proposal acknowledging that transfer capability associated with transmission reservations that are not scheduled in real time is required to be made available as non-firm, and posted on OASIS.

(8) Other OASIS Issues

Comments

390. MidAmerican, PacifiCorp and Pinnacle contend that the development of the OASIS posting requirements is technical in nature and should be addressed by the NERC and NAESB processes.

391. NRECA recommends that the Commission require public utility transmission providers to make OASIS data available in a useable, machine-readable and manipulable format to transmission customers (so they can be better prepared to make decisions about their transmission needs) and to the Commission (so that it can monitor the provision of transmission service). Similarly, Powerex states that posted data must be in sufficient detail to permit third parties to independently review and verify ATC postings and treatment of transmission service requests.

392. Utah Municipals suggest that OASIS sites be as uniform and compatible as possible and reasonably user-friendly, and that certificate fees for access to non-public sites be evaluated for legitimacy. Arkansas Commission and Seattle also express concern over the OASIS access requirements established by most transmission providers, which require viewers to purchase certificates or licenses for the particular computers from which OASIS access is sought.

393. Williams suggests that all transmission service-related business practices and local procedures, including the exercise of discretion or waiver or granting of exception, be posted on the transmission provider's OASIS. It also suggests that real-time data and import/export limits by constrained area should be posted on OASIS, along with line outages

(planned and unplanned), estimated return to service dates and de-rates of a line.

Commission Determination

394. In response to NRECA and other commenters regarding the availability and format of data available on OASIS, we note that current regulations already require that OASIS data be made available in a useable, machine-readable user friendly format to transmission customers. The improvements required in the Final Rule will enhance the level of detail posted on OASIS and, in turn, transmission customers' ability to verify the transmission provider's treatment of transmission requests. Thus, to the extent NRECA or others desire greater consistency in data formats, they should propose such revisions through the NERC and NAESB processes.

395. Regarding comments received expressing concern about the use of certificates for OASIS access, we believe that the use of such certificates can be appropriate. However, the Commission reminds transmission providers that the cost of OASIS access, whether by registration, certificate or other form of license, should be limited to a nominal charge, *e.g.*, no more than $100. This nominal fee provides funding for OASIS maintenance while assuring that all transmission customers and potential customers will not be denied access because of excessive fees.

396. With respect to Williams' request for additional OASIS postings, we agree that such additional data would be useful to transmission customers and is already posted on some ISO and RTO Web sites and, to a lesser extent, on the NERC web site (TLR data). Therefore, we require that all transmission service-related business practices and local procedures, including waivers, should be posted on or made available through OASIS. With respect to real-time data and import/export limits by constrained area, estimated return-to-service dates and line de-ratings, we are confident that most of this data is already required by this Final Rule and shall be provided whenever TTC and ATC changes in value trigger the posting of a narrative explanation of the causes of those changes. Moreover, the Final Rule requires a broad data exchange among transmission providers, including information on line outages and other data relating to ATC calculations. Accordingly, we will not require additional OASIS postings for this data.

(9) CEII

NOPR Proposal

397. Critical Energy Infrastructure Information (CEII) is information concerning proposed or existing critical infrastructure (physical and virtual) that (1) Relates to the production, generation, transportation, transmission or distribution of energy, (2) could be useful to a person in planning an attack on critical infrastructure, (3) is exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. 552, and (4) does not simply give the location of the critical infrastructure.[217] Access to such transmission related information has been restricted by the Commission's CEII regulations.[218]

398. In the NOPR, the Commission recognized that the use of the existing CEII processes could undermine their goal of providing increased transparency to information necessary to evaluate the use of the transmission system. As a result, the Commission requested comment on procedures that could be adopted by transmission providers to streamline the resolution of CEII concerns and allow timely disclosure of information from the transmission providers to interested parties.

Comments

399. APPA and other commenters argue that the additional information disclosure requirements proposed in the NOPR raise substantial CEII concerns, and request the Commission to refine its CEII procedures to allow those with legitimate need for the information to obtain it on a timely basis.[219] Bonneville would like to permit public access for stakeholders to review principles and methods used in ATC calculations, but only permit limited access, subject to background checks and non-disclosure agreements, to modeling data that may compromise infrastructure security. APPA suggests establishing a process for advance qualification for receipt of such information by those industry participants with rights to review information on the customer side of OASIS, without giving blanket public access. TDU Systems urge the Commission to adopt a streamlined process to ensure timely resolution of ATC calculation disputes and to adopt measures that ensure that CEII claims do not unduly restrict information.

400. EEI and Southern caution that the release of a transmission provider's explanation of methodologies, practices, and procedures in Attachment C may not give rise to CEII concerns, but that other information such as energy infrastructure data, models and assessments do raise security and confidentiality concerns. They propose that a transmission provider have the ability to seek confidential treatment of such information. Allegheny proposes that an independent third party or Commission staff review and explain ATC calculations to interested parties without disclosing CEII.

401. Several commenters believe that much of the information the Commission proposes to require transmission providers to provide will not pose CEII concerns.[220] However, Entergy states that some of the information requires protection as proprietary information because its public availability over OASIS would reveal commercially sensitive information. ISO New England also points out that information relevant to the ATC calculation may be market-sensitive

402. Pinnacle believes the current CEII process is not unduly burdensome and urges the Commission to continue to apply the existing CEII procedures, which allow transmission customers with digital certificates or passwords to access publicly restricted transmission information.

Commission Determination

403. The Commission acknowledges that certain data and studies required to be made public under this Final Rule may contain CEII. The Commission has a responsibility to protect this information. However, the Commission agrees with APPA, Bonneville, and TDU Systems that those with a legitimate need for CEII information must be able to obtain it on a timely basis. The Commission also shares EEI and Southern's concerns that the data, models and assessments used to calculate ATC may contain information that raises security and confidentiality concerns, and ISO New England and Entergy's concerns about commercial and market-sensitive information.

404. In order to provide transparency and avoid undue delays in providing information to those with a legitimate need for it, the Commission requires

[217] *See Critical Energy Infrastructure Information*, Order No. 683, 71 FR 58273 (Oct. 3, 2006), FERC Stats. & Regs. ¶ 31,228 at P 66 (2006), *reh'g pending*. We note that the Commission is proposing to change the definition of CEII in a proceeding in Docket No. RM06–23–000. *See Critical Energy Infrastructure Information*, Notice of Proposed Rulemaking, 71 FR 58325 (Oct. 3, 2006), FERC Stats. & Regs. ¶ 32,607 (2006).

[218] *See* 18 CFR 388.112–113.

[219] *E.g.*, MidAmerican, Sacramento, Southern, and TVA.

[220] *E.g.*, Nevada Companies, East Texas Cooperatives, PJM, and TDU Systems.

transmission providers to establish a standard disclosure procedure for CEII required to be disclosed by this Final Rule. We note that transmission customers already have digital certificates or passwords to access publicly restricted transmission information on OASIS. Transmission providers may set up an additional login requirement for users to view CEII sections of the OASIS, requiring users to acknowledge that they will be viewing CEII information. Transmission providers may require customers to sign a nondisclosure agreement at the time that the customer obtains access to this portion of the OASIS. Only information that meets the criteria for CEII, as defined in section 388.113 of the Commission's regulations,[221] should be posted in this section of the OASIS. Transmission providers will be responsible for identifying CEII and facilitating access to it by appropriate entities, and the Commission will be available to resolve disputes if they arise.

(10) Additional Data Posting

NOPR Proposal

405. To further reduce discretion in calculating ATC/AFC, the Commission proposed that transmission providers post on OASIS metrics related to the provision of transmission service under their OATT. In the NOPR, the Commission proposed to require the monthly posting of (1) The number of affiliate versus non-affiliate requests for transmission service that have been rejected and (2) the number of affiliate versus non-affiliate requests for transmission service that have been made. This posting would also detail the length of service request (*e.g.*, short-term or long-term) and the type of service requested (*e.g.*, firm point-to-point, non-firm point-to-point or network service). The Commission sought comments regarding whether it should require transmission providers to post their underlying load forecast assumptions for all ATC calculations and, on a daily basis their actual daily peak load for the prior day. Finally, the Commission asked for comment on the overall benefit of posting the proposed metrics, on potential alternative metrics, and on working through NAESB to develop standards for consistent methods of posting the new requirements on OASIS.

Comments

406. PJM and other commenters support the proposal to post data showing acceptances and denials of transmission service requests of non-affiliates and affiliates.[222] However, PJM and Ameren argue that the affiliate posting requirement should not apply to RTOs and ISOs, because they are independent, have no affiliates, and lack incentive to favor one transmission customer over another. MDEA requests clarification on how the additional posting requirements would be applied under Entergy's weekly procurement process. Entergy notes on reply that the Commission has already established metrics to measure the performance of its weekly procurement process, and the creation of further metrics are beyond the scope in a generic rulemaking. Entergy further points out that non-affiliated generating facilities that are designated as network resources to serve native load also benefit from transmission service obtained in this manner. It suggests that NAESB is the best forum for considering such issues and developing specific procedures for calculating these metrics. TranServ suggests that there are other useful metrics that NAESB should be directed to define, such as average time to evaluate requests and confirm requests, and percentage of requests denied, approved and withdrawn.

407. PJM notes its support of proposed OASIS posting reforms, but cautions that all industry groups must have an equitable and proportionate voice in NAESB if it is requested to develop standards. It also expresses concern that PJM and other RTOs have established a practice of posting a significant amount of data for participants' use in formats and applications which respective members have requested and approved through stakeholder processes.

408. APPA points out that the data on transmission denials would be useful to the Department of Energy (DOE) in reporting on congestion in its triennial congestion studies to be prepared under FPA section 216(a), and that NAESB may be able to provide standard formats for disclosure of such data. Some APPA members express a preference for NERC to develop these standards, while others stress the need for regional variation in posting requirements.

409. Ameren questions whether the posting requirement would serve the Commission's objective of identifying undue discrimination even in cases where the transmission provider is not an RTO or other independent transmission provider, because the metrics can lead to incorrect impressions. MidAmerican also states that the proposed posting would require sophisticated analysis to yield useful benefits.

410. EEI is not opposed to the proposal to post metrics on acceptance and denial of requests for transmission service, but suggests such information is already available on OASIS and that any customer or the Commission staff can develop its own metrics. Southern also states that this data is currently available.

411. Several commenters support the posting of forecast and actual daily peak loads.[223] Ameren states that the proposed requirement would produce a useful comparison, increase transparency, and provide the ability to verify that an appropriate amount of capacity is being set aside for native load. E.ON states that RTO and ISO forecasts and actual data need to be posted with sufficient granularity to allow for meaningful comparison of control area and LSE load levels. EEI requests that the Commission clarify that its proposal to require the posting of peak loads applies to system-wide loads and not only to the native load of the transmission provider. It also seeks clarification that the differences between forecast and actual system peak loads not result in any repercussions.

412. APPA members in the East generally favor the proposal to post the load information, but its members in the West expressed concerns about the competitive implications of providing such data. Additional commenters express concern about data confidentiality.[224] TAPS contends that providing for data disclosure on a one-day lag basis would alleviate these commercial concerns, but it also suggests that the Commission should require the disclosure of projected load forecast information on request to a customer's non-market employees or agents.

Commission Determination

413. The Commission adopts the proposed requirement to post on OASIS metrics related to the provision of transmission service under the OATT. Specifically, transmission providers must post (1) The number of affiliate versus non-affiliate requests for transmission service that have been rejected and (2) the number of affiliate versus non-affiliate requests for

[221] 18 CFR 388.113.

[222] *E.g.*, Arkansas Commission, Constellation, MidAmerican, MDEA, Morgan Stanley, Nevada Companies, NRECA, Suez Energy NA, and TranServ.

[223] *E.g.,* Ameren, Constellation, E.ON, Nevada Companies, NRECA, Powerex, Suez Energy NA, TAPS, TDU Systems, and TranServ.

[224] *E.g.,* E.ON, Entergy, LDWP, and TranServ.

transmission service that have been made. This posting must detail the length of service request (*e.g.*, short-term or long-term) and the type of service requested (*e.g.*, firm point-to-point, non-firm point-to-point or network service). The Commission also will require transmission providers to post their underlying load forecast assumptions for all ATC calculations and, to post on a daily basis, their actual daily peak load for the prior day. The Commission directs transmission providers to work through NAESB to develop standards for consistent methods of posting the new requirements on OASIS.

414. The Commission agrees with PJM and Ameren that affiliate posting requirements do not apply to RTOs and ISOs, since they do not have affiliates to transact with. The Commission also agrees with Entergy that the metrics established for its weekly procurement process are outside the scope of this proceeding.

415. In response to Southern's point that the information necessary to compute the metrics is already available on OASIS, while it is true that service denial information is available on OASIS for long periods, request information is not. As such, a customer would need to continuously download information from OASIS to record the data sufficient to calculate the metrics on its own. The Commission concludes that it is not unduly burdensome for transmission providers to calculate the metrics required by this Final Rule.

416. With regard to posting of load forecasts and actual daily peak load, we conclude that such postings are necessary to provide transparency for transmission customers. We agree with E.ON that RTO and ISO load data needs to be posted at a sufficient granularity to allow for meaningful comparison of control area and LSE load levels. Most RTOs and ISOs post load data for the entire footprint, but few post it on an LSE or control area basis. We therefore direct ISOs and RTOs to post load data for the entire ISO/RTO footprint and for each LSE or control area footprint within the ISO/RTO. This will not create an undue burden on ISOs and RTOs, since the load data for the entire footprint is an aggregation of load data across the LSEs or control areas in the footprint. We also agree with EEI that the peak load applies to system-wide load, including native load. We direct transmission providers to post load forecasts and actual daily peak load for both system-wide load (including native load) and native load, as this data will be useful to customers and regulators. We deny EEI's request for a guarantee that transmission providers will not be held accountable for producing a reasonable load forecast. While we do not intend to penalize transmission providers for failing to account for unforeseen circumstances, we retain our ability to investigate any allegations of manipulation of load forecasts, as this could be used as a means of inappropriately denying requested transmission service.

417. The Commission is not convinced by the views of some commenters that load data has competitive implications. The Commission notes, as PJM pointed out in its comments, that many RTOs have an established practice of posting significant amounts of load data for participants' use, and this data posting has not raised competitive concerns.

B. Coordinated, Open and Transparent Planning

1. The Need for Reform

418. Order No. 888 set forth certain minimum requirements for transmission system planning. For example, Order No. 888 and the *pro forma* OATT require that transmission providers plan and upgrade their transmission systems to provide comparable open access transmission service for their transmission customers. With regard to network service, section 28.2 of the *pro forma* OATT provides that the transmission provider ''will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System.'' Section 28.2 also provides that the Transmission Provider shall, consistent with Good Utility Practice, ''endeavor to construct and place into service sufficient transfer capability to deliver the Network Customer's Network Resources to serve its Network Load on a basis comparable to the Transmission Provider's delivery of its own generating and purchased resources to its Native Load Customers.''

419. The *pro forma* OATT also requires that new facilities be constructed to meet the service requests of long-term firm point-to-point customers. Section 13.5 of the *pro forma* OATT requires the transmission provider to consider redispatch of the system to relieve any constraints that are inhibiting a transmission customer's point-to-point service if it is economical to do so; but if redispatch is not economical, the transmission provider is obligated to expand or upgrade its system. This expansion obligation on the part of the transmission provider for point-to-point service is found in section 15.4 of the *pro forma* OATT, which provides that, when a transmission provider cannot accommodate a request for point-to-point transmission because of insufficient capability on its system, it will ''use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service.'' Section 15.4 goes on to provide that ''the Transmission Provider will conform to Good Utility Practice in determining the need for new facilities and in the design and construction of such facilities.'' The transmission provider's obligation to upgrade or expand its system to provide point-to-point service as detailed in section 15.4 is contingent on the transmission customer agreeing to compensate the transmission provider for such costs pursuant to the terms of section 27 (providing for cost responsibility for upgrades and/or redispatch ''to the extent consistent with Commission policy'').

420. In Order No. 888–A, the Commission encouraged utilities to engage in joint planning with other utilities and customers and to allow affected customers to participate in facilities studies to the extent practicable. The Commission also encouraged regional planning so that the needs of all participants are represented in the planning process.[225] Order No. 888–A did not, however, require that transmission providers coordinate with either their network or point-to-point customers in transmission planning or otherwise publish the criteria, assumptions, or data underlying their transmission plans. The Commission also did not require joint planning between transmission providers and their customers or between transmission providers in a given region.[226] The only section of the existing *pro forma* OATT that directly speaks to joint planning is section 30.9, which provides that a network customer must receive credit when facilities constructed by the customer are jointly planned and installed in coordination with the transmission provider.[227]

[225] *See* Order No. 888–A at 30,311.

[226] *See id.*

[227] *Pro forma* OATT section 21.2, ''Coordination of Third-Party System Additions,'' provides for certain rights for transmission providers to coordinate construction of facilities on their systems associated with point-to-point customer requests and related construction on a third-party transmission system, but imposes no obligation on transmission providers.

421. As the Commission stated in the NOPR, the Nation has witnessed a decline in transmission investment relative to load growth in the ten years since Order No. 888 was issued. Transmission capacity per MW of peak demand has declined in every NERC region. Transmission constraints plague most regions of the country, as reflected in the limited amounts of ATC posted in many regions, increased frequency of denied transmission requests, increasingly common transmission service interruptions or curtailments and rising congestion costs in organized markets.[228]

422. We do not believe that the existing *pro forma* OATT is sufficient in an era of increasing transmission congestion and the need for significant new transmission investment. We cannot rely on the self-interest of transmission providers to expand the grid in a nondiscriminatory manner. Although many transmission providers have an incentive to expand the grid to meet their State-imposed obligations to serve, they can have a disincentive to remedy transmission congestion when doing so reduces the value of their generation or otherwise stimulates new entry or greater competition in their area. For example, a transmission provider does not have an incentive to relieve local congestion that restricts the output of a competing merchant generator if doing so will make the transmission provider's own generation less competitive. A transmission provider also does not have an incentive to increase the import or export capacity of its transmission system if doing so would allow cheaper power to displace its higher cost generation or otherwise make new entry more profitable by facilitating exports.

423. As the Commission explained in Order No. 888, ''[i]t is in the economic self-interest of transmission monopolists, particularly those with high-cost generation assets, to deny transmission or to offer transmission on a basis that is inferior to that which they provide themselves.'' [229] The court agreed on review of Order No. 888, noting in *TAPS* v. *FERC* that ''[u]tilities that own or control transmission facilities naturally wish to maximize profit. The transmission-owning utilities thus can be expected to act in their own interest to maintain their monopoly and to use that position to retain or expand the market share for their own generated electricity, even if they do so at the expense of lower-cost generation companies and consumers.'' [230] The Supreme Court in *New York* v. *FERC* similarly explained that ''public utilities retain ownership of the transmission lines that must be used by their competitors to deliver electric energy to wholesale and retail customers. The utilities' control of transmission facilities gives them the power either to refuse to deliver energy produced by competitors or to deliver competitors' power on terms and conditions less favorable than those they apply to their own transmissions.'' [231]

424. The existing *pro forma* OATT does not counteract these incentives in the planning area because there are no clear criteria regarding the transmission provider's planning obligation. Although the *pro forma* OATT contains a general obligation to plan for the needs of their network customers and to expand their systems to provide service to point-to-point customers, there is no requirement that the overall transmission planning process be open to customers, competitors, and State commissions.[232] Rather, transmission providers may develop transmission plans with limited or no input from customers or other stakeholders. There also is no requirement that the key assumptions and data that underlie transmission plans be made available to customers.

425. Taken together, this lack of coordination, openness, and transparency results in opportunities for undue discrimination in transmission planning. Without adequate coordination and open participation, market participants have no means to determine whether the plan developed by the transmission provider in isolation is unduly discriminatory. This means that disputes over access and discrimination occur primarily after-the-fact because there is insufficient coordination and transparency between transmission providers and their customers for purposes of planning.[233] The Commission has a duty to prevent undue discrimination in the rates, terms, and conditions of public utility transmission service and, therefore, an obligation to remedy these transmission planning deficiencies. As we explain above, our authority to remedy undue discrimination is broad.[234] In addition, new section 217 of the FPA requires the Commission to exercise its jurisdiction in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of LSEs. A more transparent and coordinated regional planning process will further these priorities, as well as support the DOE's responsibilities under EPAct 2005 section 1221 to study transmission congestion and issue reports designating National Interest Electric Transmission Corridors and the Commission's responsibilities under EPAct 2005 section 1223.

NOPR Proposal

426. In order to provide for more comparable open access transmission service, limit the potential for undue discrimination and anticompetitive conduct, and satisfy its statutory responsibilities under section 217 of the FPA, the Commission proposed to amend the *pro forma* OATT to require coordinated, open, and transparent transmission planning on both a local and regional level. Each public utility

[228] The number of TLRs has increased significantly since NERC started reporting annual statistics. The total number of TLRs each year has grown from under 500 in 1998 and 1999 to around 2000 over the last four years from 2002 to 2006. The number of TLR actions at the highest levels, requiring curtailment of firm transmission flows, has also grown, from under 10 before 2001 to 70 in 2006, averaging 55 per year from 2003 to 2006. Source: NERC Web site, *ftp://ftp.nerc.com/pub/sys/all_updl/oc/scs/logs/trends.htm*. In addition, congestion costs continue to be a major issue in RTO markets. For example, congestion costs in PJM were $2.09 billion in calendar year 2005, which was a 179 percent increase over 2004. Although this increase resulted primarily from increases in PJM annual billings, the congestion costs in both years were approximately 9 percent of total PJM billings in both years and have ranged from 6 percent to 10 percent of total billings since 2000. Source: 2005 PJM State of the Markets Report, April 2006.

[229] Order No. 888 at 31,682.

[230] 225 F.3d at 684.

[231] 535 U.S. at 8–9 (citation and footnotes omitted).

[232] As discussed in more detail in the NOPR, the need for reform was recognized by the Consumer Energy Council of America (CECA), a public interest energy policy organization with a 30-year history of bringing stakeholders together to find solutions to contentious energy policy issues. CECA launched its Transmission Infrastructure Forum in early 2004, which published its conclusions in January 2005 in a final report titled ''Keeping the Power Flowing: Ensuring a Strong Transmission System to Support Consumer Needs for Cost-Effectiveness, Security and Reliability'' (CECA Report). Among other things, the CECA Report concludes that regional transmission planning with consumer input early in the process is needed to ensure the development of a robust transmission system capable of meeting consumer needs reliably and at reasonable cost over time. The CECA Report stresses that regional transmission planning must address inter-regional coordination, the need for both reliability and economic upgrades to the system, and critical infrastructure to support national security and environmental concerns. *See* NOPR at P 207.

[233] In our discussion of enforcement issues at section V.E of this Final Rule, we note specific situations in which transmission providers have agreed to resolve staff allegations that they engaged in OATT violations involving transactions with affiliates. While these specific situations may not directly relate to discrimination in planning, they nevertheless document the continuing incentive of transmission providers to favor themselves and their affiliates in the provision of transmission service.

[234] *See* Order No. 888 at 31,669 (noting that the FPA ''fairly bristles'' with concern for undue discrimination (*citing AGD,* 824 F.2d at 998).

transmission provider would be required to submit, as part of its compliance filing in this proceeding, a proposal for a coordinated and regional planning process that complies with the following eight planning principles: Coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, and congestion studies. In the alternative, transmission providers could make a compliance filing in this proceeding describing their existing coordinated and regional planning processes and showing that they are consistent with or superior to that required in the Final Rule.

427. The Commission stated that it expected non-public utility transmission providers to participate in the proposed planning processes, given that effective regional planning cannot occur without the participation of all transmission providers, owners, and customers. Although the Commission encouraged the use of an independent third party to oversee or coordinate the planning process, the NOPR did not propose to require it. The Commission also strongly encouraged the participation of State commissions and other State agencies in planning activities.

428. The Commission sought comment on several aspects of the NOPR proposal. First, the Commission inquired as to the level of flexibility each transmission provider should be given in implementing any principles adopted. Second, the Commission sought comment, by way of example, on transmission planning processes that comply with the NOPR reforms in principle. Third, the Commission sought comment on whether there are other principles or requirements that should be adopted to support the construction of needed new infrastructure and otherwise ensure that all market participants are treated on a comparable basis. Specifically, the Commission inquired: (a) Whether there should be a principle or guideline to govern the recovery and allocation of costs associated with funding the regional planning requirement; (b) whether there should be a requirement that, at least for large new transmission projects, there be an open season to allow market participants to participate in joint ownership of these projects; (c) whether there should be a specific study process to identify opportunities to enhance the grid for purposes beyond maintaining reliability or reducing current congestion; and, (d) whether public utilities should be required to develop cost allocation principles to address the sharing of the costs of new transmission projects and, given that such projects can take years to construct, whether the planning process should be required to look out at least as far as the longest time it would take to build such an upgrade in the region in question. Finally, the Commission sought comment on the level of detail to be required in transmission providers' OATTs.

Comments

429. Most commenters support the development of coordinated, open, and transparent planning. While differing on how they should be implemented, commenters express broad support for the eight planning principles,[235] though all RTOs and ISOs and many investor-owned utilities believe that their planning processes already comply with the proposals in the NOPR. ISO/RTO Council, as well as individual RTOs and ISOs, advance the position that RTOs and ISOs already meet the planning requirements in the NOPR, that there has been no credible case made for reopening their already approved planning processes, and that RTOs and ISOs should be exempt from complying with the NOPR's planning principles.

430. Some transmission providers agree that RTOs already meet the principles, and others argue against commenters who maintain that RTOs ''rubber stamp'' transmission provider plans.[236] For example, MISO asserts that it conducts an open planning process and does not ''rubber stamp'' projects. Duke concurs with MISO, stating that there are abundant opportunities for participation in the MISO planning process. Xcel also replies in support of the MISO process.

431. Several transmission customers, however, argue that current RTO processes are insufficient because, among other things, they merely accept the transmission owners' plans and only provide for after-the-fact input, thus failing to satisfy the planning principles proposed in the NOPR.[237] Old Dominion also asserts that RTOs generally approve transmission owner identified upgrades, which give them the advantage of having their own parochial plans incorporated into the regional plan without any separate evaluation or complete stakeholder input. TAPS asserts that open planning should apply both to the RTO and the underlying transmission owners' planning efforts. In its reply, WPS opposes MISO's proposal to be exempt from the NOPR's planning requirements, arguing that the MISO process is not open and only aggregates the plans of the transmission providers.

432. EEI takes issue with broad statements in the NOPR that assert that transmission providers have a disincentive to remedy transmission congestion and to plan their transmission systems on a comparable basis. Other individual investor-owned utilities also assert that the record does not support the NOPR's claims that a mandatory coordinated, open, and transparent planning process is necessary to remedy undue discrimination.[238] Many others, however, believe the NOPR correctly diagnoses the problem of discrimination.[239]

433. Most commenters do not question the Commission's jurisdiction to address the transmission planning process generally. Southern, however, argues that the Commission has no general authority in this area and that section 217 of the FPA does not grant the Commission any additional jurisdiction to impose a regional planning requirement.[240] FMPA counters that the Commission has FPA authority to cure undue discrimination and to ensure ''just and reasonable'' transmission rates and terms by adopting transmission planning criteria.[241] In their replies, APPA and TAPS agree with the Commission that FPA section 217(b)(4) can be cited as legal support for transmission planning. In its reply, NRECA stresses that the transmission planning process must focus, consistent with FPA section 217(b)(4), on the reasonable long-term needs of LSEs, not all users of the system as argued by EPSA and NRG. Santee Cooper urges the Commission to be mindful of the limits of its jurisdiction in establishing study requirements that may delve into generation resource adequacy or issues related to the mix of generation. Other commenters urge the Commission not to impinge on State jurisdiction.[242] In its reply, LPPC emphasizes that the Commission's expectation that public power entities will participate is

[235] The one exception is the congestion studies requirement, which is generally opposed by transmission providers and supported by customers.

[236] *E.g.,* Duke, Exelon, and Xcel.

[237] *E.g.,* Indicated Parties Reply, Old Dominion, NRECA, and TAPS.

[238] *See, e.g.,* Duke and Southern.

[239] *See, e.g.,* APPA and EPSA. However, NRG and Reliant believe that the planning process outside of RTOs is fundamentally flawed and cannot be remedied by the NOPR's planning proposal.

[240] Progress Energy also claims that the Commission does not have any jurisdiction to mandate regional planning.

[241] *See also* TAPS Reply.

[242] *See, e.g.,* Nevada Companies, New Mexico Attorney General, North Carolina Commission Reply, and Southern.

sufficient and asserts that there is no reason to take further action that might test the limits of jurisdiction under FPA section 211A.[243]

434. WIRES endorses several planning objectives it believes to be critical to successful planning. These objectives include open and transparent planning procedures, a long-term planning horizon, broad-based inclusion of reliability, economic, efficiency and environmental considerations in planning, clear conditions under which a transmission owner will commit to build planned facilities, and provision for fair and efficient allocation of the costs of planned facilities. WIRES also emphasizes the importance of considering non-transmission alternatives, arguing that an appropriate grid plan must be based on an integrated view of all alternatives, including demand response and distributed generation.

Commission Determination

435. In order to limit the opportunities for undue discrimination described above and in the NOPR, and to ensure that comparable transmission service is provided by all public utility transmission providers, including RTOs and ISOs, the Commission concludes that it is necessary to amend the existing *pro forma* OATT to require coordinated, open, and transparent transmission planning on both a local and regional level. We disagree with commenters arguing either that we lack jurisdiction to require coordinated transmission planning or that we have not established a basis for such a requirement. The Commission has broad authority to remedy undue discrimination by ensuring that transmission providers plan for the needs of their customers on a comparable basis.[244] That fundamental requirement was adopted in Order No. 888 and the reforms adopted herein should ensure that it will be implemented properly. Further, we explained in detail above why undue discrimination remains a concern in the planning area and why the existing OATT is insufficient to address that concern.

436. New section 217 of the FPA further supports reform in this area, as it reflects Congress' intent that the Commission utilize its powers to facilitate the planning and expansion of the transmission system.[245] Through EPAct 2005 sec. 1223, Congress also directed the Commission to encourage the deployment of advanced transmission technologies in infrastructure improvements, including among others optimized transmission line configurations (including multiple phased transmission lines), controllable load, distributed generation (including PV, fuel cells, and microturbines), and enhanced power device monitoring.

437. Accordingly, each public utility transmission provider is required to submit, as part of a compliance filing in this proceeding, a proposal for a coordinated and regional planning process that complies with the planning principles and other requirements in this Final Rule.[246] In the alternative, a transmission provider (including an RTO or an ISO, as discussed below), may make a compliance filing in this proceeding describing its existing coordinated and regional planning process, including the appropriate language in its tariff, and show that this existing process is consistent with or superior to the requirements in this Final Rule. Under either of these approaches, the process must be documented as an attachment to the transmission provider's OATT.

438. At the outset, we note that the planning obligations imposed in this Final Rule do not address or dictate which investments identified in a transmission plan should be undertaken by transmission providers. Furthermore, except for the discussion below of cost allocation for transmission investments under Principle 9, the planning obligations included in this Final Rule do not address whether or how investments identified in a transmission plan should be compensated. Through the principles described below, we establish a process through which transmission providers must coordinate with customers, neighboring transmission providers, affected State authorities, and other stakeholders in order to ensure that transmission plans are not developed in an unduly discriminatory manner.

439. As for the application of the Final Rule's coordinated planning requirement to RTOs and ISOs, which already have a Commission-approved transmission planning process on file with us, we note that the intent of our reform in this Final Rule is not to reopen prior approvals, but rather to ensure that the transmission planning process utilized by each RTO and ISO is consistent with or superior to the planning process adopted here. When the Commission approved the existing RTO and ISO transmission planning processes, they were found to be consistent with or superior to the existing *pro forma* OATT. Because the *pro forma* OATT is being reformed by this Final Rule, it is necessary for each RTO and ISO to now either reform its process or show that its planning process is consistent with or superior to the *pro forma* OATT, as modified by the Final Rule.

440. We also make clear that transmission owning members of ISOs and RTOs must participate in the planning processes adopted in this Final Rule. In order for an RTO's or ISO's planning process to be open and transparent, transmission customers and stakeholders must be able to participate in each underlying transmission owner's planning process. This is important because, in many cases, RTO planning processes may focus principally on regional problems and solutions, not local planning issues that may be addressed by individual transmission owners. These local planning issues, however, may be critically important to transmission customers, such as those embedded within the service areas of individual transmission owners. Consequently, the intent of the Final Rule will not be realized if only the regional planning process conducted by the RTOs and ISOs is shown to be consistent with or superior to the Final Rule. To ensure full compliance, individual transmission owners must, to the extent that they perform transmission planning within an RTO or ISO, comply with the Final Rule as well. Without such a requirement, the more regional RTO or

[243] Other jurisdictional arguments primarily relate to the question of joint ownership, in which some commenters argue that the Commission lacks jurisdiction to mandate joint ownership arrangements. *See, e.g.*, Duke, EEI, National Grid, Northeast Utilities, PSEG, and Southern. FMPA and others, however, argue that the Commission does have the authority to order joint ownership. Joint ownership will be discussed more fully below.

[244] *See AGD,* 824 F.2d at 1008 (Commission has broad discretion to promulgate generic rules to eliminate undue discrimination without ''conduct[ing] experiments in order to rely on the prediction that an unsupported stone will fall'').

[245] FPA section 217(b)(4) provides that ''[t]he Commission shall exercise the authority of the Commission under [the FPA] in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long term basis for long term power supply arrangements made, or planned, to meet such needs.''

[246] The *pro forma* OATT, as modified by this Final Rule, reflects the proposed planning requirement in sections 15.4, 16.1, 17.2(x), 28.2, 29.2, 31.6. The planning process itself will be included as Attachment K to the *pro forma* OATT. We understand that some transmission providers may already have attachments to their OATTs labeled with the letter ''K,'' in which case transmission providers are free to label their planning process OATT attachment with the next available letter.

ISO planning process will not comply with the requirements of the Final Rule to the extent they incorporate and rely on information prepared by underlying transmission owners that, in turn, have not complied with the Final Rule. Accordingly, as part of their compliance filings in this proceeding, RTOs and ISOs must indicate how all participating transmission owners within their footprint will comply with the planning requirements of this Final Rule. While we leave the mechanics of such compliance to each RTO and ISO, we emphasize that the RTO's or ISO's planning processes will be insufficient if its underlying transmission owners are not also obligated to engage in transmission planning that complies with Final Rule.[247]

441. The Commission also expects all non-public utility transmission providers to participate in the planning processes required by this Final Rule. A coordinated, open, and transparent regional planning process cannot succeed unless all transmission owners participate. We are encouraged, based on the representations of LPPC and others, that non-public utility transmission providers will fully participate in such processes. We therefore do not believe it is necessary at this time to invoke our authority under FPA section 211A, which gives us authority to require non-public utility transmission providers to provide transmission services on a comparable and not unduly discriminatory or preferential basis.[248] If we find on the appropriate record, however, that non-public utility transmission providers are not participating in the planning processes required by this Final Rule, the Commission may exercise its authority under section 211A on a case-by-case basis. Further, we note that reciprocity dictates that non-public utility transmission providers that take advantage of open access due to improved planning should be subject to the same requirements as jurisdictional transmission providers.

442. In sum, each OATT planning process attachment must incorporate the transmission planning principles and concepts in this Final Rule and must be filed with the Commission within 210 days after the publication of the Final Rule in the **Federal Register.** Alternatively, RTOs, ISOs, and other transmission providers that currently have planning processes they believe comply with the Final Rule may make a filing with the Commission documenting those processes in an OATT attachment and explaining how their planning processes are consistent with or superior to the planning process adopted here. Such filings must also be submitted within 210 days after the publication of the Final Rule in the **Federal Register.**

443. In order to assist transmission providers in complying with the Final Rule, and ensure that the planning procedures are developed with customer and stakeholder participation, the Commission will convene staff technical conferences in several broad regions around the country to discuss regional implementation and other compliance issues in advance of the compliance date. We extend an invitation to State regulatory commissions to participate in these technical conferences with our staff in order to ensure that State concerns are fully addressed. The Commission will endeavor to hold the technical conferences 90 to 120 days after the publication of the Final Rule in the **Federal Register.** To facilitate these conferences, each transmission provider should, within 75 days after the publication of the Final Rule in the **Federal Register**, post a ''strawman'' proposal for compliance with each of the planning principles adopted in the Final Rule, including a specification of the broader region in which it will conduct coordinated regional planning. This strawman may be posted on the transmission provider's OASIS, or its Web site if it does not have its own OASIS (*e.g.*, in the case of a transmission owning member of an RTO or ISO that does not have its own OATT). We strongly urge transmission providers to consult with their stakeholders in the development of this strawman.

2. Planning Principles

444. We set forth below the planning principles that must be satisfied for a transmission provider's planning process to be considered compliant with the Final Rule. The NOPR identified eight such principles, but based on the comments received the Commission will require compliance with nine—the original eight plus a cost allocation principle, as described further below.

a. Coordination

445. In the NOPR, the Commission proposed that transmission providers must meet with all of their transmission customers and interconnected neighbors to develop a transmission plan on a nondiscriminatory basis. We sought comment on specific requirements for this coordination, such as the minimum number of meetings to be required each year, the scope of the meetings, the notice requirements, the format, and any other features deemed important by commenters.

Comments

446. Commenters express universal support for the general concept of coordination, but differ on how specific the requirement should be. Several commenters argue that the requirement that transmission providers ''must meet'' with customers and utilities is unrealistic.[249] EEI requests that the Commission clarify that transmission providers will be responsible for coordinating with customers and holding meetings, but that the requirement to meet should be limited to making reasonable efforts to meet with all customers. NRECA asks on reply that the Commission make clear that the lack of full participation by some nonjurisdictional utilities that take network service under the OATT should not excuse the transmission provider's obligation to engage in transmission planning. NRECA states that inclusion in the planning process must be an opportunity for LSEs, not an obligation.

447. Other commenters express a more general concern that the Commission not be prescriptive with respect to meeting requirements.[250] For example, most commenters generally believe the Commission should not prescribe rigid rules regarding the number of meetings that must be held

[247] We understand that there are some transmission owners in RTOs or ISOs that continue to have OATTs on file under which they provide service over certain transmission facilities that they did not turn over to the operational control of the RTO or ISO. Like any other transmission provider, those entities must submit a compliance filing to their OATTs that satisfies all requirements of this Final Rule, including the inclusion of an attachment governing their own planning procedures. As we explain elsewhere, the compliance filing deadline for transmission owning participants in RTOs and ISOs shall be the same as the RTO and ISO deadline, *i.e.*, 210 days after publication of the Final Rule in the **Federal Register.**

[248] FPA section 211A(b) provides, in pertinent part, that ''the Commission may, by rule or order, require an unregulated transmitting utility to provide transmission services—(1) At rates that are comparable to those that the unregulated transmitting utility charges itself; and (2) on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential.'' The non-public utility transmission providers referred to in this Final Rule include unregulated transmitting utilities that are subject to FPA section 211A.

[249] *E.g.,* Allegheny, Duke, EEI, International Transmission, MidAmerican, NorthWestern, and SCE.

[250] *E.g.,* Allegheny, APPA, Bonneville, California Commission, Duke, Entergy, Imperial, International Transmission, MidAmerican, NCEMC, NC Transmission Planning Participants Reply, NorthWestern, NRECA, Pinnacle, Progress Energy, CREPC, Santee Cooper, SCE, TVA, and WAPA.

each year. Xcel, however, suggests that a minimum of three meetings a year would be appropriate. Progress notes that coordination in North Carolina already occurs as a result of regular meetings throughout the year. Nevada Companies believe that meetings should be dependent on need and should not be programmatically established. TDU Systems recommend at least monthly meetings, but stress that meetings should be as frequent as is required to specify and perform the studies forming the basis for the plan. NCPA believes that the minimum requirements are not as important as how they can be monitored or enforced to ensure that true participation indeed occurs.

448. Seattle suggests 30 days notice for meetings and that information regarding meetings be posted at least one week in advance. Entergy finds a notice requirement reasonable, and other utilities suggest a 30-day requirement would be appropriate.[251] Seattle also suggests e-mail notification and Salt River supports internet posting. With respect to details beyond frequency and notice, Entergy cautions the Commission against being too prescriptive.

449. On meeting scope, several commenters request that the Commission make clear that the purpose of the meeting is to focus on transmission issues and not provide a broad forum for other issues.[252] Sacramento believes that meetings should be limited to sub-regional or regional transmission planning and not include planning to meet local transmission needs.

450. Other commenters stress that joint planning requires more than just meeting with customers and that all LSEs need to be integrated into the planning process so that they are actively developing transmission plans alongside transmission providers from the inception.[253] This concept of collaborative planning is a running theme in the comments provided by several public power entities, such as NRECA, TAPS, and TDU Systems. TDU Systems argue that comparability requires that LSEs have equal weight in decision-making rather than provide de facto veto authority to transmission providers. NRECA argues in its reply that collaborative planning is required by FPA section 217(b)(4). These commenters assert that LSEs must be able to participate in the development of planning models, including the assumptions and criteria that go into these models, and in the development of the base case and change case for study purposes, particularly as to the identification and projection of loads and resources.[254] Progress and Southern, however, argue in replies that giving customers equal weight in decision-making crosses the line from planning to control by third parties, and Southern believes this would be opposed by State regulators.

Commission Determination

451. The Commission adopts the coordination principle proposed in the NOPR. Commenters overwhelmingly desire flexibility as to the coordination principle, and as such, we will not prescribe the requirements for coordination, such as the minimum number of meetings to be required each year, the scope of the meetings, the notice requirements, the format, and any other features. We will allow transmission providers, with the input of their customers and other stakeholders, to craft coordination requirements that work for those transmission providers and their customers and other stakeholders.

452. We emphasize that the purpose of the coordination requirement is to eliminate the potential for undue discrimination in planning by opening appropriate lines of communication between transmission providers, their transmission-providing neighbors, affected State authorities, customers, and other stakeholders. Rigid and formal meeting procedures may be one way to accomplish this goal, but there may be other ways as well. For example, a transmission provider could meet this requirement by facilitating the formation of a permanent planning committee made up of itself, its neighboring transmission providers, affected State authorities, customers, and other stakeholders. Such a planning committee could develop its own means of communication, which may or may not emphasize formal meeting procedures. We are more concerned with the substance of coordination than its form.

453. In response to the concerns of some commenters, we clarify that transmission providers are not required to meet with customers and other stakeholders that choose not to meet. Transmission providers cannot force others to meet with them. Transmission providers are, however, required to craft a process that allows for a reasonable and meaningful opportunity to meet or otherwise interact meaningfully. We also clarify that the coordination requirements imposed in this Final Rule are intended to address transmission planning issues, and are not intended to provide a forum for ancillary issues, such as specific siting concerns, which are better addressed elsewhere. As for NRECA's concern that transmission providers must plan for their nonjurisdictional network customers even if they decline to fully participate in the planning process, a transmission provider cannot be expected to effectively plan for a customer if that customer declines to engage in the planning process. Therefore, we encourage NRECA and non-public utilities to participate fully in the planning process.

454. In response to the suggestion by some commenters that we require transmission providers to allow customers to collaboratively develop transmission plans with transmission providers on a co-equal basis, we clarify that transmission planning is the tariff obligation of each transmission provider, and the *pro forma* OATT planning process adopted in this Final Rule is the means to see that it is carried out in a coordinated, open, and transparent manner, in order to ensure that customers are treated comparably. Therefore, the ultimate responsibility for planning remains with transmission providers. With this said, we fully intend that the planning process adopted herein provide for the timely and meaningful input and participation of customers into the development of transmission plans. This means that customers must be included at the early stages of the development of the transmission plan and not merely given an opportunity to comment on transmission plans that were developed in the first instance without their input.

b. Openness

455. In the NOPR, the Commission proposed that transmission planning meetings must be open to all affected parties (including all transmission and interconnection customers and State authorities). The Commission also sought comment on whether there are any circumstances under which participation should be limited, for example, to address confidentiality concerns.

[251] *E.g.,* Nevada Companies and NorthWestern.

[252] *E.g.,* Entergy, Progress Energy, SCE, and Southern.

[253] *E.g.,* NRECA, Seminole Reply, TAPS, and TDU Systems.

[254] This collaborative approach is also generally supported by East Texas Cooperatives, FMPA, NCEMC, NCPA, and Old Dominion. NCEMC believes that the key to ensuring true collaboration is a voting structure, like that adopted in the North Carolina Transmission Planning Collaborative, which gives all load-serving entities an equal say in planning decisions. APPA also believes that giving customers a say in the outcome (*e.g.,* through voting) is critical.

Comments

456. Commenters generally agree on the need to meet with all affected parties, as well as the need to limit some meetings for security or confidentiality reasons. Certain commenters urge the Commission to make clear that openness does not extend to a requirement to meet with the general public and that the meetings are for ''industry and governmental representatives'' only.[255] For example, Southern agrees that eligible transmission customers and State commissions should be allowed to participate in the meetings, but states that these meetings should not be open to the general public to help ensure that the focus is on core transmission planning and not be diverted to other issues.

457. Transmission providers generally note that some meetings will need to be limited for CEII concerns or for discussion of commercially-sensitive information.[256] Progress Energy states the Commission should be flexible regarding the composition of meetings and openness, noting that in North Carolina meetings involving CEII are limited to transmission personnel and non-marketing personnel of participating LSEs, while other meetings in the North Carolina process are open to the public. In their reply, NC Transmission Planning Participants note that they have been able to negotiate confidentiality protocols agreeable to each of them. Duke believes that restrictions on open meetings need to be in place when sensitive commercial information is being discussed, so that personnel engaged in the merchant function do not gain access to sensitive information about their competitors. Indianapolis Power recommends the Commission keep existing restrictions on access to planning meetings in place to preserve current protections on security and competitive information. TVA states that it is particularly concerned with maintaining confidentially and asks the Commission to defer to NERC and its Regional Entities, which TVA says are developing procedures for planning.

458. Commenters also raise issues regarding the application of the Commission's Standards of Conduct to those that participate in planning meetings.[257] EEI, for example, believes that if information is disclosed during a planning meeting and is not simultaneously made public, then all planning participants—including nonjurisdictional entities—should be subject to the Commission's Standards of Conduct. APPA understands the need to ensure that non-public information obtained during planning meetings is not utilized to gain an unfair advantage in the power market; however, it believes that other means short of the application of the Standards of Conduct would suffice, such as requiring simultaneous disclosure of information as a ''safe harbor'' or the use of confidentiality agreements.[258]

459. NRECA and TDU Systems argue that meetings should be open and, joined by APPA, suggest that confidentiality issues can be managed with confidentiality agreements and other arrangements (such as password protected access to information). TAPS suggests that access to data be limited to transmission dependent utility employees not involved in marketing or to an outside consultant. California Commission stresses that any advisory subcommittees must also be open to all stakeholders.

Commission Determination

460. The Commission adopts the NOPR's proposal and will require that transmission planning meetings be open to all affected parties including, but not limited to, all transmission and interconnection customers, State commissions and other stakeholders. We recognize that it may be appropriate in certain circumstances, such as a particular meeting of a subregional group, to limit participation to a relevant subset of these entities. We emphasize, however, that the overall development of the transmission plan and the planning process must remain open. We agree with the concerns of some commenters that safeguards must be put in place to ensure that confidentiality and CEII concerns are adequately addressed in transmission planning activities. Accordingly, we will require that transmission providers, in consultation with affected parties, develop mechanisms, such as confidentiality agreements and password-protected access to information, in order to manage confidentiality and CEII concerns. Lastly, concerns surrounding the application of the Commission's Standards of Conduct to planning participants, and whether and how these standards should affect access to and use of information obtained in the planning process, will be discussed below.

c. Transparency

461. In the NOPR, the Commission proposed that transmission providers be required to disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie their transmission system plans. The Commission also sought comment on whether the information provided in FERC Form 715 (Form 715) is adequate and, if not, what additional detail should be provided. In addition, the Commission sought comment on the format for disclosure, including protections to address confidentiality concerns.

Comments

462. Transmission providers generally agree that they should provide the basic criteria, assumptions, and data for planning, but argue that non-public utility transmission providers should also be required to provide comparable information.[259] In general, EEI believes that information provided during the planning process should be treated as confidential and not disclosed to the general public.

463. Public power entities and other commenters support transparency and also are sensitive to confidentiality concerns.[260] NCPA believes that the failure of CAISO to release planning data is one of the biggest failings of CAISO planning process. Without access to criteria, assumptions, and data inputs, NCPA argues that customers cannot duplicate planning results, nor can they independently determine whether the assumptions are correct, whether the model is producing the right results, whether those results are being fairly applied in the choice of projects to be undertaken, or assess the impacts on their own customers. APPA suggests that transmission providers be required to reduce to writing the methodology, criteria, and processes they use to develop their transmission plans, including how they treat retail native loads, in order to ensure that standards are consistently applied.

[255] *E.g.*, APPA, EEI, Salt River, and Southern.

[256] Other commenters also recognize the need to maintain confidentiality for CEII and commercially-sensitive information. *E.g.*, Arkansas Commission, AWEA, California Commission, NCPA, NRECA, CREPC, Seattle, TDU Systems, and WAPA.

[257] Commenters raise issues with regard to the application of the Commission's Standards of Conduct to planning participants in their comments addressing some of the other principles as well, which will be discussed below, as well as addressed in the pending rulemaking in Docket No. RM07–1–000. *See* Standards of Conduct NOPR.

[258] *See also* East Texas Cooperatives Reply and NRECA Reply.

[259] *E.g.*, CAISO, EEI, and SCE.

[260] *E.g.*, APPA, California Commission, NCPA, CREPC, Salt River, and WAPA. Old Dominion, however, does not believe that any of the data required to be disclosed is commercially-sensitive; however, it does recognize that it may be CEII, in which case it claims security can be maintained via a secure OASIS site.

CREPC points out that transparency is necessary if State regulatory processes are to give deference to planning results. Sacramento asserts that it may be reasonable to allow customers and stakeholders access to the planning model or at least allow access to a comprehensive description of the model and methodology, in order to allow others to closely replicate the planning analysis. Sacramento is joined by Imperial in referencing WECC's ongoing effort to increase planning transparency.

464. NRECA and TDU Systems, however, do not believe that a specific disclosure principle would be necessary if LSEs were truly integrated into the planning process. In other words, they argue that if the process is truly open, then LSEs, as participants in the development of the joint plan, should already have access to the inputs and assumptions underlying the plans and, in fact, should have helped develop them.

465. EEI believes that Standards of Conduct requirements should be placed on all participants in the planning process whenever disclosure of commercially-sensitive information is needed for planning. East Texas Cooperatives argues that the Standards of Conduct should not be generically applied to public power and that such issues should be managed with confidentiality agreements and case-by-case protective orders. In its reply, NRECA also asserts that, while it is necessary to protect competitively-sensitive information, there is no basis for requiring nonjurisdictional entities to comply with the formal separation of functions requirements simply because they have received information in the planning process, as this is inconsistent with the cooperative utility business model. Rather, NRECA believes commercially-sensitive information can be handled in other established ways. APPA also suggests that Standards of Conduct issues can be managed by providing for certain ''safe harbors'' for participation, such as simultaneous disclosure of information or the use of an independent facilitator.[261]

466. Commenters express a range of views on the information found in Form 715. MidAmerican believes Form 715 to be more than adequate and recommends shortening or eliminating it. Other investor-owned utilities find Form 715 to be generally sufficient.[262] Others believe the information in Form 715, as currently supplemented by other information in the planning process, is adequate.[263] Duke and WAPA contend that Form 715 does not contain sufficient information for transmission planning, but believe that disclosure of further details should be left to stakeholders. According to NorthWestern, Form 715 contains the basic data, but may not always provide the needed information.

467. ISO/RTO Council believes that Form 715 data are generally inadequate for planning studies, but urges the Commission not to attempt to develop ''standardized forms'' for these and other types of data. CAISO also cautions against adopting a standardized form for the collection of necessary information, because standardized forms do not necessarily provide the information needed by individual providers.

468. A number of other commenters believe that Form 715 information is insufficient.[264] APPA and TAPS point out that Form 715 does not include all the information needed to perform a load flow study, including information on economic dispatch and interchange, and also that Form 715 information is out of date when filed. Seattle notes that typical sub-regional planning processes go into significantly greater detail than Form 715 and argues that Form 715 is primarily a reliability-focused report that seldom delves into economic analysis of congestion and transmission options that mitigate congestion.

469. Several commenters contend that transparency in the planning process is of particular interest to demand resources. New Jersey Board suggests that each transmission provider's planning process analyze whether demand resources or other solutions could be considered as an alternative or a component of new transmission lines or upgrades. New Jersey Board states that this analysis should include both supply-side and demand-side measures such as load management, new building codes and energy efficiency standards, the use of distributive renewable energy systems, and renewable portfolio standards. Ohio Power Siting Board argues that an open, transparent, and inclusive regional planning process should include distributed generation, demand response, and new technology as part of the mix of available options for incremental or interim congestion relief until longer term solutions can be developed and constructed. Fayetteville notes its general support for a SEARUC joint planning proposal, which includes a principle that would require the integration of demand response in planning. WIRES likewise argues that an appropriate grid plan should be based on an integrated view of all alternatives, including demand response and distributed generation. PJM, Midwest ISO, and ISO New England emphasize that their planning processes already provide for the evaluation and integration of demand response resources.[265] Other commenters, such as Alcoa and Steel Manufacturer's Association, suggest that demand response resources be considered as substitutes for certain ancillary services.

470. In response to its notice convening the October 12 Technical Conference, the Commission received several comments addressing the role of demand response in planning. Participants in the technical conference generally responded that demand response programs are considered in planning, particularly in the load forecasts. Some observed that demand response has often been difficult to incorporate in long-term plans when it is not dispatchable and only available in one-year increments. Participants stressed that transmission providers must have control over a resource throughout the planning horizon if they are to rely on that resource in lieu of constructing upgrades. Some participants reported that this capability is available from several forms of demand response resources.

Commission Determination

471. The Commission adopts the NOPR's proposal and will require transmission providers to disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie their transmission system plans.[266] In addition, transmission

[261] NARUC asks the Commission to re-examine the need for its Standards of Conduct rules concerning communications between resource and transmission planners in light of the mitigation provided by the open planning processes proposed in the NOPR.

[262] E.g., Indianapolis Power, Southern, and Xcel.

[263] *E.g.*, Allegheny (with data from PJM) and Nevada Companies (with data from WECC).

[264] *E.g.*, APPA, California Commission, NCPA, CREPC, Seattle, TAPS, and TDU Systems. California Commission and CREPC also point out that the load forecast information presently used in planning in the Western Interconnection is likewise insufficient.

[265] *See also* ISO/RTO Council.

[266] Much of the information should be available to those engaged in transmission planning already under reliability Standards TPL–001–0 through TPL–004–0 proposed in Docket RM06–16–000. *See* the Reliability Standards NOPR. These standards set out detailed requirements for annual studies to assess the performance of the transmission system and require conducting simulation studies over a five-year time horizon, with additional studies as needed for the six to ten-year horizon. The Commission proposed that planning entities conduct ''studies to bracket the range of probable outcomes,'' examining system operation under variations in demand levels, existing and planned facilities, reactive power resources, generation dispatch and transaction patterns, controllable

providers will be required to reduce to writing and make available the basic methodology, criteria, and processes they use to develop their transmission plans, including how they treat retail native loads, in order to ensure that standards are consistently applied. This information should enable customers, other stakeholders, or an independent third party to replicate the results of planning studies and thereby reduce the incidence of after-the-fact disputes regarding whether planning has been conducted in an unduly discriminatory fashion. We note, however, that transmission providers cannot be expected to fulfill these planning obligations unless non-public utility transmission providers that participate in the planning process make similar information available and, for the reasons set forth above, we fully expect that they will do so. We believe that the same safeguards developed as discussed above regarding the openness principle, such as confidentiality agreements and password protected access to information, will adequately protect against inappropriate disclosure of confidential information or CEII.

472. The Commission also requires that transmission providers make available information regarding the status of upgrades identified in their transmission plans in addition to the underlying plans and related studies. It is important that the Commission, stakeholders, neighboring transmission providers, and affected State authorities have ready access to this information in order to facilitate coordination and oversight. To the extent any such information is confidential or consists of CEII, the transmission provider can implement the safeguards suggested above.

473. In response to the concerns of some commenters regarding the disclosure of information to non-public utility transmission providers, we believe that simultaneous disclosure of transmission planning information where appropriate alleviates many of those concerns. In those instances where there is non-simultaneous disclosure of information, we find that existing reciprocity requirements ensure that information is not inappropriately shared with the non-public utility transmission provider's marketing affiliate.

loads and demand-side management, and other factors. *Id.* at P 1047. While we recognize that OATT planning is distinct from these proposed reliability planning standards, we expect that the key data underlying transmission planning will be provided in conjunction with reliability standards and thus should be available for transmission planning when those standards are finalized.

474. In Order No. 888–A, the Commission clarified that, under the reciprocity condition, a non-public utility transmission provider must also comply with the OASIS and Standards of Conduct requirements or obtain waiver of them.[267] We reiterate that non-public utility transmission providers should abide by the Standards of Conduct with regard to managing non-public transmission planning information obtained through the planning process, consistent with their reciprocity obligations. We also note that, given the planning process required by this Final Rule, it may be necessary to revisit the waivers of the Standards of Conduct granted to certain non-public utility transmission providers in the past. We will not do so, however, on a generic basis in this proceeding. All such existing waivers thus shall remain in place. Whether an existing waiver of the Standards of Conduct should be revoked will be considered on a case-by-case basis in light of the circumstances surrounding the particular transmission provider.[268]

475. In order for the Final Rule's transmission planning process to be as effective as possible, we emphasize that all transmission providers, both jurisdictional and nonjurisdictional, must be assured that the information they provide in that process will not be used inappropriately in the wholesale power market. While we decline to require a third party independent facilitator as discussed below, we do believe that utilizing an independent entity may help parties manage Standards of Conduct concerns.[269] Finally, we wish to emphasize that the Commission recognizes that compliance with the Standards of Conduct can impose costs on small entities, but we believe that this concern must be balanced against the fact that a coordinated and open transmission planning process is critical to remedying undue discrimination and meeting our Nation's future energy needs and that an open planning process cannot be fully successful if certain entities (whether jurisdictional or nonjurisdictional) can use the information to obtain an undue advantage in power markets. We therefore intend to balance the costs of confidentiality restrictions with the importance of not allowing any entity an undue competitive advantage in addressing this issue on a case-by-case basis.

[267] *See* Order No. 888–A at 30,286.

[268] We believe this same approach should also apply to public utilities that have obtained waivers of the Standards of Conduct.

[269] The Commission will consider whether further changes to the Standards of Conduct would facilitate the transmission planning requirement in the Standards of Conduct NOPR initiated in Docket No. RM07–1–000. *See supra* note 257. We also intend to address the concerns of NARUC with regard to waiving the Standards of Conduct concerning communications between resource and transmission planners in that proceeding.

476. Although we adopt the foregoing protections to ensure that particular entities do not gain an inappropriate competitive advantage over others, we believe that transmission providers should make as much transmission planning information publicly available as possible, consistent with protecting the confidentiality of customer information. Given that one of the primary objectives of the planning reforms adopted herein is to allow customers to consider future resource options, it will be necessary for market participants, including the merchant function of transmission providers, to have access to basic transmission planning information in order to consider those options. The simultaneous disclosure of transmission planning information can alleviate the Standards of Conduct concerns discussed above.[270]

477. In response to commenter concerns regarding the sufficiency of planning information currently available in the Form 715, we find that Form 715, as well as Form 714, have not provided customers and others with the timely data needed to perform load flow studies and other analyses to ensure that planning is being conducted on a comparable basis. For example, while we understand that certain planning information is already provided in FERC Form No. 714 (Annual Electric Control and Planning Area Report) and FERC Form 715 (Annual Transmission Planning and Evaluation Report), we believe that with regard to transparency of data and assumptions, Forms 714 and 715 are limited in a number of ways. An important limitation is that information is not necessarily available on a consistent geographic basis. Form 715 requires selected powerflow studies by

[270] Transmission providers could ensure simultaneous disclosure of information through such actions as providing all current and potential customers and other stakeholders equal access, notice, and opportunity to attend planning meetings, providing for the contemporaneous availability of meeting handouts and minutes on the transmission providers' OASIS or Internet Web sites, and requiring that an energy affiliate or marketing affiliate employee of the transmission provider may not attend a meeting unless a representative of at least one additional customer or potential customer is present. We believe such actions would typically constitute compliance with sections 358.5(a) and (b) of the Standards of Conduct, 18 CFR 358.5(a)–(b), dealing with information access and prohibited disclosure, respectively.

control area, while Form 714 requires information on control area generation and load, including hourly load on a planning area. Since these two areas do not necessarily coincide, it can be difficult to apply the data except for the single annual or seasonal system peak. Consequently, Form 715 is an insufficient basis for broad transmission planning purposes and must be supplemented by additional assumptions and data.

478. Information may also be difficult to compare or apply if a region is larger than a single control area. Where the peak periods represented in the Form 715 correspond to different time periods in different control areas, separate assumptions and information may be needed for a study encompassing multiple control areas. In addition, each control area may include different criteria for including facilities in the data and additional assumptions will be needed to resolve these issues as well. Moreover, information on the basis for key assumptions is limited. The Form 715 instructions require a description of transmission planning reliability criteria and assessment practices, but allow the transmitting utility discretion on what is reported. As a result, assumptions regarding key inputs, such as the load forecasts, are not available. Similarly, information regarding customer demand response is not available. Lastly, Form 715 requires no information explaining the basis for generator dispatch in the powerflow cases, nor is any economic information provided. For studies of system peak reliability, when all generators are expected to be running, this may not be a significant limitation. However, without some basis for dispatching the system at other times, it becomes difficult or impossible to conduct meaningful load flow studies for other planning purposes. Therefore, we will require the disclosure of criteria, assumptions, data, and other information that underlie transmission plans as described above.

479. Finally, several commenters assert that demand response resources should be considered in transmission planning.[271] Some commenters note that certain regions currently are in the process of incorporating demand response into their transmission planning processes.[272] Demand resources currently provide ancillary services in some regions, and this capability is in under development in some others.[273] We therefore find that, where demand resources are capable of providing the functions assessed in a transmission planning process, and can be relied upon on a long-term basis, they should be permitted to participate in that process on a comparable basis.[274] This is consistent with EPAct 2005 section 1223.

d. Information Exchange

480. In the NOPR, the Commission proposed that network transmission customers be required to submit information on their projected loads and resources on a comparable basis (*e.g.*, planning horizon and format) as used by transmission providers in planning for their native load. The Commission further proposed that point-to-point customers be required to submit any projections they have of a need for service over that planning horizon and at what receipt and delivery points. The Commission sought comment on whether specific requirements should be adopted for this information exchange.[275] The Commission also stated that transmission providers must allow market participants the opportunity to review and comment on draft transmission plans.

Comments

481. Transmission providers suggest that they should be responsible for developing a schedule and format for submission of information and the development of a draft plan that provides sufficient time for participants to review and comment before completion of a final plan.[276] EEI emphasizes the importance of requiring comparable information from all participants in planning, including non-public utilities. EEI maintains that similarly-situated participants should have comparable information, with commercially-sensitive information available only to transmission function personnel. Duke supports the information exchange principle in general, but believes the NOPR envisions a wider exchange of information on loads and resources than is appropriate.[277] Instead, Duke believes that planning participants should agree on how much detail will be available. WAPA similarly suggests that any criteria for information exchange should be developed by stakeholders, not the Commission.

482. Although commenters do not generally disagree with a requirement for point-to-point customers to submit projections of their needs for service, they question the value of these projections if the customers have not actually requested service for these projected needs.[278] Nevada Companies state that point-to-point customers should provide future use forecasts and that the forecast data transferred by all entities should be provided for the planning horizon in a uniform manner.

483. Southern is concerned that the opportunity for review and comment could be construed to apply to draft interconnection, system impact, or facilities studies under the transmission provider's OATT. Southern argues that such a requirement would cause great delay and asks the Commission to clarify that the transparency requirement for review and comment on transmission plans is limited to only the transmission provider's draft of its base case transmission plan.

484. Other commenters advance a view that joint planning should consist of more than providing the transmission provider with information and then reviewing and commenting on the plans it develops; rather, customers need to be able to actively participate in the development of the planning studies and transmission plans.[279] APPA likewise believes that earlier involvement is needed so that projected needs are fully understood and accounted for in the initial development of the plan.[280] NCPA stresses that reviewing plans is meaningless if there is no access to data on how the plan was created, how economic evaluation was

[271] *E.g.*, Ohio Power Siting Board, New Jersey Board, and WIRES.

[272] *E.g.*, PJM and ISO–New England.

[273] *See* Staff Report: Assessment of Demand Response & Advanced Metering at 97–100 (Docket Number AD–06–2–000) (Demand Response Report), *available at http://www.ferc.gov/legal/staff-reports/demand-response.pdf#xml=http://search.atomz.com/search/pdfhelper.tk?sp_o=1,100000,0.*

[274] The transmission planning processes we require in this Final Rule are not intended in any way to infringe upon State authority with regard to integrated resource planning. Rather, we believe that the transparency provided under an open regional transmission planning process can provide useful information which will help states to coordinate transmission and generation siting decisions, allow consideration of regional resource adequacy requirements, facilitate consideration of demand response and load management programs at the State level, and address other factors states wish to consider.

[275] The Commission noted in the NOPR that for network service, some of this information is already required by sections 29, 30, and 31 of the *pro forma* OATT, but to the extent it is not, the Commission proposed to require customers to provide additional information as necessary for the transmission provider to develop a system plan.

[276] *E.g.,* EEI, Pinnacle, Salt River, and Xcel.

[277] TVA states that it is unaware of any shortcomings with the existing information exchange process and that more specific requirements may limit the ability of transmission providers to meet changing needs and processes.

[278] *E.g.,* APPA, Duke, and Salt River.

[279] *E.g.,* NCPA and TDU Systems.

[280] *See also* Bonneville, California Commission, Imperial, NCPA, and Seattle.

performed, and how and why proposed upgrades were chosen. Old Dominion suggests that planning information and data be posted no less than monthly or, where appropriate, seasonally. TDU Systems and NCEMC stress that LSEs should have access to all information at the same time since if a transmission provider performs studies without including other LSEs, it opens the door for providers to act on sensitive information before releasing it to other LSEs.

485. Some commenters advance the view that distributed generation and other demand response resources should be considered in developing a transmission plan.[281]

Commission Determination

486. The Commission adopts the information exchange principle as to both network and point-to-point transmission customers. Accordingly, we will require transmission providers, in consultation with their customers and other stakeholders, to develop guidelines and a schedule for the submittal of information. In order for the Final Rule's planning process to be as open and transparent as possible, the information collected by transmission providers to provide transmission service to their native load customers must be transparent and, to that end, equivalent information must be provided by transmission customers to ensure effective planning and comparability. We clarify that the information must be made available at regular intervals to be identified in advance. Information exchanged should be a continual process, the frequency of which should be addressed in the transmission provider's compliance filing required by the Final Rule. However, we expect that the frequency and planning horizon will be consistent with ERO requirements.

487. We also believe that it is appropriate to require point-to-point customers to submit any projections they have of a need for service over the planning horizon and at what receipt and delivery points. We believe that any good faith projections of a need for service, even though they may not yet be subject to a transmission reservation, may be useful in transmission planning as they may, for example, provide planners with likely scenarios for new generation development. If the point-to-point customers do not submit such projections, then the transmission provider cannot later be faulted for failing to consider planning scenarios that might have taken into account reasonable projections of future system uses that were not the subject of specific service requests. To the extent applicable, transmission customers also should provide information on existing and planned demand resources and their impacts on demand and peak demand. In addition, stakeholders should provide proposed demand response resources if they wish to have them considered in the development of the transmission plan.

488. Lastly, in response to the concerns of some commenters, we emphasize that the transmission planning required by this Final Rule is not intended, as discussed earlier, to be limited to the mere exchange of information and then review of transmission provider plans after the fact. The transmission planning required by this Final Rule is intended to provide transmission customers and other stakeholders a meaningful opportunity to engage in planning along with their transmission providers. At the same time, we emphasize that this information exchange relates to planning, not other studies performed in response to interconnection or transmission service requests.

e. Comparability

489. In the NOPR, the Commission proposed that, after considering the data and comments supplied by market participants, each transmission provider develop a transmission system plan that (1) Meets the specific service requests of its transmission customers and (2) otherwise treats similarly-situated customers (*e.g.*, network and retail native load) comparably in transmission system planning.

Comments

490. Several commenters support the comparability principle,[282] and others state that existing processes already follow this principle.[283] EEI urges the Commission to emphasize that the ''comparability'' principle requires the transmission provider or transmission owner to treat similarly-situated participants comparably in the development of a plan, but does not require that all participants be treated equally. Pinnacle and others support comparable treatment of similarly-situated customers and request the Commission to confirm that native load protections will be recognized in the concept of comparability.[284] New Mexico Attorney General asserts that native load and non-affiliated merchants and other wholesale customers should not be treated comparably, because utilities have a statutory obligation to serve.

491. TDU Systems and the NRECA repeat the view that comparability cannot be achieved if the transmission provider is the only one developing the plan, which they believe this principle contemplates. They argue instead that LSEs should be allowed to participate actively in the development of the plan from the beginning and should have equal weight in decision-making. TDU Systems believes that comparability does not allow for different planning standards for certain customers, because it may leave rural electric cooperatives out of the planning loop.[285] TAPS also argues that comparability is not enough; rather, substantive goals should be included.[286]

492. Noting that not all transmission service requests may be granted, Southern urges the Commission to clarify that the intent of this criteria is that the transmission provider plan its system so as to be able to reliably serve all of its long-term firm commitments on its transmission system in accordance with its State and Federal legal requirements, as well as ERO Standards. With regard to RTO and ISO planning, NYAPP argues that it is not comparable for an RTO or ISO to only plan for bulk power facilities, while allowing individual transmission owners the discretion to plan for lower voltage transmission facilities.

493. Some commenters argue that demand resources should be treated comparably to other resources in transmission planning.[287]

Commission Determination

494. The Commission adopts the NOPR's proposal as to the comparability principle and will require the transmission provider, after considering the data and comments supplied by customers and other stakeholders, to develop a transmission system plan that (1) Meets the specific service requests of

[281] *E.g.*, New Jersey Board, Ohio Power Siting Board, and WIRES.

[282] *E.g.*, California Commission, NCPA, CREPC, Salt River, Seattle, and WAPA.

[283] *E.g.*, Duke and Imperial.

[284] *See also* MidAmerican, Progress Energy, and Xcel.

[285] *See also* NRECA Reply and Old Dominion.

[286] TAPS cites to its ''Balanced Principles for Transmission Planning & Expansion,'' which was attached to its NOI comments, for a description of the following substantive goals: (1) Reliability/adequacy, (2) accommodating load growth, (3) preserving existing transmission rights, (4) access to regional competitive generation markets, (5) maintaining deliverability, (6) facilitating regional/inter-regional power transfers, and (7) integrating new generation into the regional grid. TAPS emphasizes that the process should anticipate needs and propose solutions before serious transmission problems emerge.

[287] *E.g.*, ELCON, New Jersey Board, and WIRES.

its transmission customers and (2) otherwise treats similarly-situated customers (*e.g.*, network and retail native load) comparably in transmission system planning.[288] Further, we agree with commenters that customer demand resources should be considered on a comparable basis to the service provided by comparable generation resources where appropriate.

495. We are specifically requiring a comparability principle to address concerns, such as those raised by commenters, that transmission providers continue to plan their transmission systems such that their own interests are addressed without regard to, or ahead of, the interests of their customers. Comparability requires that the interests of transmission providers and their similarly-situated customers be treated on a comparable basis. In response to the concerns expressed by several commenters, we emphasize that similarly-situated customers must be treated on a comparable basis, not that each and every transmission customer should be treated the same.[289]

f. Dispute Resolution

496. In the NOPR, the Commission proposed that transmission providers propose a dispute resolution process, such as requiring senior executives to meet prior to the filing of any complaint and using a third party neutral. The Commission noted that the Commission's Dispute Resolution Service is available to assist transmission providers in developing a dispute resolution process. The Commission also noted that, in addition to informal dispute resolution, affected parties would have the right to file complaints with the Commission under FPA section 206. The Commission sought comment on whether any specific dispute resolution processes should be required.

Comments

497. Many commenters support the proposed dispute resolution principle,[290] while others believe existing processes, including section 12 of the *pro forma* OATT, are sufficient.[291] Other commenters simply urge flexibility in the development of a dispute resolution process.[292] However, maintaining that the Commission has no legal authority to mandate a regional planning process or dispute resolution related thereto, Progress states the Commission should be flexible and allow for a voluntary dispute resolution process.[293]

498. Southern believes that dispute resolution should be limited to whether a provider has complied with any procedural requirements and not be utilized by parties to modify a transmission plan. APPA, however, argues that such an approach would relegate customers to an advisory role. EEI believes the Commission should include principles for dispute resolution and should allow stakeholders in the regional planning groups to craft their own procedures consistent with those principles. Reflecting concerns of some of its members, EEI cautions against mandating dispute resolution that includes binding resolution of whether, how, where, or when to construct additional transmission facilities.

499. Indianapolis Power believes there should be a dispute resolution process in place with specific steps identified, expressing reservations about the vagueness of the current MISO process. ATC argues that RTO plans should recognize which entity is ultimately accountable for building transmission, by requiring transmission customers that have a dispute with a plan first to appeal to the local transmission owner to ensure both entities fully understand what is being requested, before carrying the dispute further.

500. Consistent with its focus on integrated joint planning, TDU Systems asks that the Commission clarify that a dispute resolution process is not being required as a principle as an acknowledgement that transmission providers will retain control over the process. As long as LSEs are an integral part of the planning process, TDU Systems stress that there should be no need for an elaborate dispute resolution process.

Commission Determination

501. The Commission adopts the NOPR's proposal to require transmission providers to develop a dispute resolution process to manage disputes that arise from the Final Rule's planning process.[294] An existing dispute resolution process may be utilized, but those seeking to rely on an existing dispute resolution process must specifically address how its procedures will be used to address planning disputes. The dispute resolution process should be available to address both procedural and substantive planning issues, as the purpose for including a dispute resolution process is to provide a means for parties to resolve all disputes related to the Final Rule's planning process before turning to the Commission.

502. We emphasize that the intent of the dispute resolution process required here is not to address issues over which the Commission does not have jurisdiction, such as a transmission provider's planning to serve its retail native load or State siting issues. As discussed above, however, we do intend that the planning process required by this Final Rule ensure comparability in planning between that conducted for a transmission provider's retail native load and its similarly-situated transmission customers and, therefore, issues relating to such comparability may be appropriate for the dispute resolution process.

503. Lastly, we encourage transmission providers, customers, and other stakeholders to utilize the Commission's Dispute Resolution Service to help develop a three step dispute resolution process, consisting of negotiation, mediation, and arbitration. Regardless of the process adopted by a transmission provider, affected parties of course would retain any rights they may have under FPA section 206 to file complaints with the Commission.

g. Regional Participation

504. In addition to preparing a system plan for its own control area on an open and nondiscriminatory basis, the Commission proposed in the NOPR that each transmission provider be required to coordinate with interconnected systems to: (1) Share system plans to ensure that they are simultaneously feasible and otherwise use consistent

[288] As discussed above, we emphasize that the obligation imposed herein on transmission providers is meant to include transmission owners in RTOs and ISOs that no longer have their own OATTs, as well as non-public utility transmission providers required to comply with the Final Rule's planning process consistent with their reciprocity obligations.

[289] Additionally, in our discussion of the coordination principle above, we clarify that transmission planning is the tariff obligation of each transmission provider, and as such, ultimate responsibility for planning remains with transmission providers. Accordingly, we reject the arguments made by some commenters that comparability requires that customers have equal weight in decision-making.

[290] *E.g.,* APPA, Bonneville, California Commission, Imperial, and NCPA.

[291] *E.g.,* East Texas Cooperatives, Salt River, Seattle, TVA and WAPA. TVA points out that since planning and its principles are just now being formed, resources would be better spent on developing platforms where interested parties could have input into the planning process, as opposed to dispute resolution.

[292] *E.g.,* Allegheny, Nevada Companies, Pinnacle, and Southern. Xcel, however, does not believe any dispute resolution process is required in the OATT.

[293] *See also* Duke and MidAmerican.

[294] We have already addressed arguments concerning our jurisdiction to require a transmission planning process. A process for resolving disputes that arise from that planning process is a necessary incident to it.

assumptions and data, and (2) identify system enhancements that could relieve ''significant and recurring'' transmission congestion (defined below). The Commission emphasized that such coordination should encompass as broad a region as possible, given the interconnected nature of the transmission grid and the efficiency of addressing these issues in a single forum. The Commission also recognized that, as in the West, it may be appropriate to organize regional planning efforts on both a sub-regional and regional level. The Commission sought comment on whether there are existing institutions (such as the NERC regional councils or sub-regional planning groups) that are well-situated to perform or coordinate this function.

Comments

Regional Scope

505. EEI agrees that regional planning should be encouraged, but urges the Commission not to be prescriptive about the size of the regions involved. According to EEI, the Commission should define regional planning as planning that involves more than one transmission provider and allow the regions to define themselves. CAISO believes the Commission should leave the determination of the sub-regional and regional boundaries to transmission providers. NC Transmission Planning Participants assert on reply that the participants in each regional process are in the best position determine the proper scope of the planning process for their region. NRECA argues that customers and other stakeholders should be allowed to participate in the discussion that leads to the delineation of regions. NRECA asserts that regions should be large enough to minimize the potential for seams problems for LSEs in multiple control areas. At a minimum, NRECA argues that the Commission should ensure that all public utility transmission providers coordinate with their adjoining systems to ensure that the needs of LSEs with loads and resources in different systems' areas are met.

506. TDU Systems support mandatory regional planning and believe that the Commission should specify the criteria for determining regions, rather than prescribe regional boundaries. In TDU Systems' view, ''regional'' planning at a minimum means something more than planning on an individual control area basis.[295] TDU Systems stress that the existence of sub-regional planning must not diminish the obligation to plan on a broader, more regional level. TDU Systems also believe that more than coordination is required; rather, transmission providers should be required to conduct planning on an integrated basis with, at a minimum, first-tier, adjacent interconnected systems. If a transmission provider refuses to do so, TDU Systems believe that should be considered an exercise of vertical market power and the transmission provider should lose its market-based rate authority. TDU Systems also urge the Commission to require regional planning for both reliability and economic upgrades, in order to ensure that competitive market development is not retarded by inappropriate seams at the borders of utility systems.[296] In its reply, NRECA argues that regional participation must be mandatory, because uncoordinated, unilateral planning by transmission providers severely handicaps LSEs' assembly of competitive power suppliers for their customers.

507. PJM states that transmission providers bordering RTOs should be required to participate in the RTO planning process, but MidAmerican opposes such a requirement and believes it already happens in MISO anyway. MAPP also opposes such mandatory participation, pointing out that comparability would then require that transmission providers in RTOs participate in the planning processes of non-RTO providers on their borders as well.[297] MAPP believes that currently-existing regions should have the opportunity to adjust their planning processes to meet the Commission's guidelines for regional transmission planning.

508. Indianapolis Power emphasizes that the regional scope of a transmission provider's planning process should consider grid topology and historical usage to avoid regions that are too broad or unwieldy. Indianapolis Power believes that the current MISO region may be an example of a region that is too large, but nevertheless asserts that MISO should have the primary role in coordination, with regional councils in supporting roles. AWEA recommends nine planning regions that coincide with the nine regions being established for Regional Triennial Reviews in the market-based rate rulemaking in Docket No. RM04–7–000:[298] PJM, New York, New England, Midwest, SPP, Southeast, California, Northwest, and Southwest.

509. LDWP and Salt River suggest that continued participation in existing regional and sub-regional groups should satisfy the expectation that municipally-owned transmission providers participate in open and transparent regional planning processes. Other commenters express a similar concern that the Commission not mandate any procedures that would interfere with the processes the West has already established.[299] New Mexico Attorney General believes that those already engaged in a planning process should be allowed a waiver.

510. NARUC urges the Commission to clarify that planning proposals should not interfere with or undermine existing regional planning efforts, such as those conducted by RTOs and in non-RTO areas.[300] Project for Sustainable FERC Energy Policy recommends that the Commission use the Bonneville and PJM planning processes as models for evaluating transmission provider compliance. Arkansas Commission believes that the active involvement of states can be a catalyst for regional planning.

511. National Grid believes the principles of coordination, openness, and transparency should extend to inter-regional planning and requests clarification that this is the Commission's intent for neighboring regions in a single interconnect.

Existing Institutions

512. Regarding the Commission's request for comment on whether there are existing institutions that are well-situated to coordinate regional participation, commenters express differing views regarding the identity of the regional coordinator and the size of the region over which entities should be required to coordinate. Some transmission provider commenters cite NERC regions and regional councils as well-suited for coordinating regional participation.[301] Taking an opposite view, ISO/RTO Council maintains that RTOs and ISOs are the best models for

[295] TAPS believes joint planning should include at least two transmission providers and be no smaller than a State. TAPS suggests that the transmission providers' compliance filings identify those other providers it proposes to include in its regular regional planning process.

[296] NRECA's comments on regional planning are consistent with those of TDU Systems.

[297] *See also* MidAmerican Reply.

[298] *See Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities,* Notice of Proposed Rulemaking, 71 FR 33102 (Jun. 7, 2006), FERC Stats. & Regs. ¶ 32,602 (2006).

[299] *E.g.,* California Commission, Imperial, and Salt River.

[300] *See also* NC Transmission Planning Participants Reply and North Carolina Commission Reply. Also, in its reply, North Carolina Commission urges the Commission not to be overly prescriptive with respect to the details of regional transmission planning.

[301] *E.g.,* Allegheny, Constellation, and Duke.

regional participation, because regional reliability organizations do not have mandates or authority to ensure that adequate system expansion occurs on a coordinated basis.

513. MISO is concerned the Commission intends to shift transmission planning responsibility from RTOs to the Regional Entities under the ERO, arguing that these entities have neither a sufficient level of independence nor a track record in transmission planning. TDU Systems suggest that RTOs, where they exist, should perform the regional planning function, although in some other instances it may be the regional reliability organizations. Although CAISO states that a larger regional entity with the authority to order expansion has some appeal, it contends there are too many hurdles to creating such an entity in the West. TAPS suggests a ''Regional Joint Planning Committee'' that is not dominated by transmission providers, which would direct the study process and be responsible for the development of uniform planning criteria, assumptions for base and changed cases, and transmission plans.

Existing Regional Planning Processes

The West

514. Transmission provider commenters in the West (outside California) generally recommend the Western Electricity Coordinating Council (WECC)[302] as a successful institution and an appropriate model for designating regions and developing a plan for the interconnection.[303] Many public power entities and others in the West also support WECC and suggest that it should be a primary focus when deciding which institution can provide independent regional review and coordination of grid planning in the West.[304] For example, California Commission notes that WECC's Transmission Expansion Planning Policy Committee allows for the consolidated needs of all the system operators in the Western Interconnection to be considered in the planning process and considers both reliability and economic transmission planning. California Commission also stresses that the processes in the West have resulted in transmission being built. Utah Municipals, however, are critical of the WECC process, and in reply, assert that the WECC process does not allow for effective stakeholder input, but merely review of transmission plans once they are formed. Utah Municipals also believe that sub-regional groups in its area (*e.g.*, the Southwest Transmission Expansion Plan (STEP)) are more effective and urges the Commission to focus on the effective implementation of joint plans.[305]

515. Other commenters support the sub-regional planning processes in the West as well, and generally believe the Commission should look to each sub-region's existing processes and institutions.[306] For example, commenters in the Southwest and California also support the sub-regional groups located in that region (*e.g.*, STEP and the Southwest Area Transmission Expansion Planning group (SWAT)).[307] California Commission also supports the CAISO planning process and states that CAISO works closely with stakeholders to proactively identify needed, cost effective transmission solutions through an open, non-discriminatory process that has resulted in $1.8 billion in transmission being constructed.[308] In its reply, NCPA emphasizes that the Commission should not equate the CAISO planning process with a California-wide process, because not all transmission providers in California are members of CAISO. However, California Commission notes that California, with the support of WECC, has begun the work of creating a California-wide sub-regional planning group that includes the large, unregulated municipal utilities that do not participate in CAISO.

Northeast

516. PJM, NYISO, and ISO New England all have transmission planning processes that have been approved by the Commission. ISO/RTO Council cites billions of dollars of transmission investment in the Northeast as an example of the success of these transmission planning processes and argues that these processes all satisfy the Commission's principles for coordinated, open, and transparent planning. PJM maintains that its Regional Transmission Expansion Planning Protocol is a successful and comprehensive regional planning paradigm. ISO New England also argues that its transmission planning meets the principles and further points to the Northeastern ISO/RTO Planning Coordination Protocol as providing coordinated planning across the entire Northeast region.

517. Utilities in the Northeast are generally supportive of the transmission planning in the Northeast RTOs. Designated NY Transmission Owners contend that the NYISO Comprehensive Reliability Planning Process is fully open, coordinated, and transparent and meets or exceeds each of the eight principles in the NOPR. PSEG believes the PJM planning process embodies the NOPR principles. Constellation cites the planning processes in PJM and the NYISO as examples of planning processes that, while not perfect, should serve as models for compliance filings by others. Old Dominion, however, expresses concern over continuing domination of transmission planning by transmission owners, but nevertheless commends PJM for recent efforts to include more stakeholder input in the planning process. National Grid is generally supportive of ISO New England's planning process.

Northwest

518. Several commenters in the Northwest generally support the Northwest Power Pool and the ColumbiaGrid process (which will provide for a biennial transmission expansion plan for certain entities in the Northwest).[309] Also, two groups in the Northwest are forming to address sub-regional planning in that region—the ColumbiaGrid group and the Northern Tier Transmission Group—but it is not

[302] In general, WECC and its sub-regional groups have adopted an overall division of labor whereby WECC has undertaken facilitation of interstate, commercial transmission projects and the sub-regional groups have facilitated the planning of their member providers.

[303] *E.g.,* ColumbiaGrid, MidAmerican, Nevada Companies, NorthWestern, Pinnacle, and Xcel.

[304] *E.g.,* Anaheim, APPA, California Commission, Imperial, LDWP, NCPA, PGP, Public Power Council, CREPC, Salt River, Santa Clara, Seattle, TANC, WAPA, and Western Governors. APPA notes, however, that not all of its members that support the WECC planning process support those within California.

[305] Public Power Council does not support expansion of WECC's role in coordinating planning beyond its current activities, as it believes WECC's strength lies in the area of reliability and not planning and, therefore, that WECC would be best served by focusing on reliability and standards enforcement, rather than as a participant (as a facilitator or otherwise) in commercial matters.

[306] WAPA points out that certain broad functions related to planning can be coordinated at the regional level, but that sub-regional planning is necessary in an expansive regional area, such as WAPA's service territory, in order to provide focus and detail.

[307] *E.g.,* LDWP, New Mexico Attorney General, and Salt River. LDWP also cites its involvement in the Public Power Initiative of the West, CAISO, and the Western Arizona Transmission System group.

[308] Anaheim believes that the CAISO process does not currently proactively evaluate the adequacy of the system or itself propose projects that will enhance reliability or efficiency and is based entirely upon plans presented to it by transmission owners. It notes, however, that CAISO has proposed reforms to address these issues. *See also* Anaheim Reply.

[309] *E.g.,* Bonneville, ColumbiaGrid, PGP, Public Power Council, and Seattle. APPA also notes its members' support for the sub-regional processes in the Northwest.

yet clear how such groups intend to coordinate with each other.

Southeast

519. The public power commenters in the Southeast were not as supportive of the existing regional and sub-regional planning processes in their region. TVA and Santee Cooper generally support the process conducted by the Southeast Electric Reliability Council (SERC), and Santee Cooper notes that it has had a formal joint planning process with its largest wholesale customer for more than 25 years. APPA, however, notes that its members did not generally endorse existing regional entities in the Southeast. APPA states that SERC, for example, just ''rolls up'' the transmission plans of the transmission providers, and some working groups currently exclude non-transmission owners.[310]

North Carolina

520. NCEMC points to the North Carolina Transmission Planning Collaborative (NC Transmission Planning), a joint planning process with an independent facilitator, in North Carolina. NCEMC emphasizes that more than regional coordination is required and that regional planning needs to be more than mere stakeholder review and must allow for full participation of LSEs in planning. NCEMC stresses that effective regional planning requires participation on a sufficient scale to encompass all LSEs within a natural market area in order to properly address seams issues and impacts on neighboring systems. Fayetteville does not believe NC Transmission Planning complies with the planning principles outlined in the NOPR.

Midwest

521. MISO believes its current transmission planning process represents industry best practices, arguing that it is open and inclusive and provides multiple opportunities for entities to participate. MISO Transmission Owners endorse the existing MISO transmission planning process and believe that the process already provides for regional planning and an open process with stakeholder involvement. Ohio Power Siting Board, however, claims that MISO's transmission planning process should not be regarded as best practices, stating that it is not sufficiently open and transparent. It also suggests that RTOs merely ''rubber stamp'' investor-owned utility plans. Additionally, FMPA[311] notes that MidAmerican has recently made efforts to engage in more proactive planning and has offered joint transmission investment opportunities. FMPA also points to its membership in CAPX 2020, a consortium of Upper Midwest utilities, which are jointly studying and planning for the needs of regional transmission. However, FMPA makes clear that it believes smaller customers nevertheless need a tariff requirement for planning to ensure that their needs are addressed.

Florida

522. While the Florida Commission believes that the planning process conducted by the Florida Reliability Coordinating Council (FRCC) is adequate, others, such as FMPA, do not.[312] Florida Commission states that the FRCC has instituted a transparent and inclusive planning process whereby utilities, generators, and marketers participate in joint transmission planning studies and evaluate impediments to transfer capability and determine solutions to congestion in order to enhance the reliability of the FRCC system.

Commission Determination

523. We adopt the NOPR's proposal to include a regional participation principle as a component of the Final Rule's transmission planning process. Accordingly, in addition to preparing a system plan for its own control area on an open and nondiscriminatory basis, each transmission provider will be required to coordinate with interconnected systems to (1) Share system plans to ensure that they are simultaneously feasible and otherwise use consistent assumptions and data and (2) identify system enhancements that could relieve congestion or integrate new resources (discussed further below).[313]

524. As discussed earlier in this Final Rule, since the advent of open access, power markets have become regional in almost every area of the country. These regional markets provide opportunities for wholesale customers to access competitive sources of supply, rather than relying exclusively on local generation, including resources owned by their local transmission provider. However, as discussed above, it is not in the economic self-interest of transmission providers to expand the grid to permit access to competing sources of supply. A transmission provider has little incentive to upgrade its transmission capacity with its interconnected neighbors if doing so would allow competing suppliers to serve the customers of the transmission provider. We therefore find, as discussed in greater detail above, that greater coordination and openness in transmission planning is required, on both a local and regional level, to remedy undue discrimination. The coordination of planning on a regional basis will also increase efficiency through the coordination of transmission upgrades that have region-wide benefits, as opposed to pursuing transmission expansion on a piecemeal basis. The specific features of the regional planning effort should take account of and accommodate, where appropriate, existing institutions, as well as physical characteristics of the region and historical practices.

525. The Commission is encouraged that a number of voluntary coordinated and regional planning efforts have been developed throughout the country, including those administered by RTOs and ISOs and in certain sub-regions of the West and Southeast. For example, each of the Commission-approved RTOs in the Northeast, Midwest, and Southwest, as well as CAISO, provide for a coordinated and regional planning process with stakeholder input from each industry segment. There are several other promising efforts to establish voluntary coordinated and regional planning efforts around the country as noted in our discussion above of existing regional planning processes.

526. The Commission fully supports these existing efforts and believes some of them are consistent in significant respects with the nature of the reforms adopted in this Final Rule. In those regions and sub-regions that already have adopted significant reforms, the Commission's planning reforms may require only modest changes, while other regions and sub-regions may need to undertake more significant changes to the way in which transmission currently is planned. The Commission will not in this Final Rule opine on the characteristics of existing regional planning processes or their consistency with the reforms we adopt today.

[310] *See also* TDU Systems Reply.

[311] We note that FMPA filed joint comments on behalf of itself and the Midwest Municipal Transmission Group.

[312] *See also* Seminole Reply.

[313] As provided for above, transmission providers will be required to file a ''strawman'' proposal for compliance with the Final Rule's planning process within 75 days after publication of the Final Rule in the **Federal Register** that includes, among other things, a specification of the broader region in which they propose to conduct coordinated regional planning. The Commission will then convene technical conferences in several broad regions around the country to assist the participants in developing the appropriate regional planning groups to the extent they do not already exist.

Rather, each process will be addressed in the context of the relevant compliance filing. In general, however, the Commission urges participants in existing regional planning processes to closely examine whether improvements may be implemented to ensure that each regional planning process is fully consistent with the requirements of this Final Rule.

527. Finally, the Commission acknowledges the importance of identifying the appropriate size and scope of the regions over which regional planning will be performed. We agree that transmission providers, customers, affected State authorities, and other stakeholders should be involved in developing those regions. We decline to mandate the geographic scope of particular planning regions at this time. The scope of a particular planning region should be governed by the integrated nature of the regional power grid and the particular reliability and resource issues affecting individual regions and sub-regions. In very large regions, there may well be both sub-regional and regional processes. For example, in the West there are various sub-regional processes in addition to a WECC regional planning process. We believe that such an approach can work, provided that there is adequate scope to the sub-regional processes and adequate coordination between sub-regions. We expect sub-regions to coordinate as necessary to share data, information and assumptions as necessary to maintain reliability and allow customers to consider resource options that span the sub-regions.

528. In response to the commenters that indicate that regional planning already occurs today as part of the NERC planning process, we support any such processes, but reiterate that, if they are to meet the requirements of the Final Rule, they must be open and inclusive and address both reliability and economic considerations. As we discuss elsewhere in this section, customers must be allowed to request that economic upgrades be studied and, therefore, we will require transmission providers to coordinate on these issues as necessary in sub-regional or regional planning processes. To the extent the NERC processes are not considered appropriate for such economic issues, individual regions or sub-regions may develop alternative processes.

h. Economic Planning Studies

529. In the NOPR, the Commission proposed to require transmission providers to prepare studies identifying ''significant and recurring'' congestion and post such studies on their OASIS. The Commission explained that the studies should analyze and report on (1) The location and magnitude of the congestion, (2) possible remedies for the elimination of the congestion, in whole or in part, (3) the associated costs of congestion, and (4) the cost associated with relieving congestion through system enhancements (or other means). The Commission sought comment on how to define ''significant and recurring'' congestion, such as by reference to generation redispatch, repeated denials of service requests, zero ATC, frequent curtailments or a combination of these factors. The Commission noted that the required congestion studies would address both ''local'' congestion (*i.e.*, within the transmission provider's system) and congestion between control areas and sub-regions. The Commission stated that the purpose of this requirement is to ensure that affected market participants, State commissions, and the Commission understand both the costs of recurring transmission congestion and the alternatives for relieving it. The Commission sought comment on how this information should be used by transmission providers and market participants to address significant and recurring congestion.

Comments

Need for Congestion Studies

530. The Commission's proposal regarding congestion studies gave rise to a wide range of comments. Some commenters generally support requiring congestion studies.[314] East Texas Cooperatives asserts that congestion studies will greatly assist in the development of transmission plans, enable planning participants to focus on key elements of the system and assist in the preparation of the congestion studies conducted by DOE. NRECA also supports requiring congestion studies, but urges the Commission not to be prescriptive.

531. Other commenters recommend eliminating the requirement.[315] Southern, for example, argues that congestion studies could be misleading because they can imply that all congestion needs to be remedied.[316] Duke, South Carolina E&G, and Southern agree that separate studies of congestion, beyond studies performed to meet service requests, should not be required. Rather than mandating congestion studies, Southern argues that the Commission should allow participants to determine which types of transmission studies have merit. Other commenters believe that, if congestion studies are required, they should be performed at a regional level rather than by each transmission provider individually.[317]

532. The EEI position is representative of entities calling for elimination of the congestion study principle. EEI asserts that these studies in large part would be duplicative of the studies being performed by DOE pursuant to EPAct 2005.[318] EEI also argues that these studies would be costly and time-consuming and that transmission providers generally do not have access to information needed for cost impact analysis and consequently cannot assess the cost of constraints.[319] TDU Systems assert on reply that it is difficult to imagine that providers do not have the information needed or means to determine the location and magnitude of congestion on their systems, since they perform this function for themselves already. TDU Systems add that customers will readily provide any information needed for congestion studies, as it is in their interest to do so. APPA believes that customers should be expressly required to produce information to help determine the cost of congestion (*e.g.*, the additional cost to them of running or purchasing more expensive generation). TDU Systems also argues that the distinction between economic and reliability upgrades is a fiction and should be disregarded.

533. In the Western Interconnection, entities maintain that WECC will be performing congestion studies that should meet the requirement. As a result, they assert that this principle should not be applied to individual transmission providers in the West, but that these providers should be permitted to meet the principle through the interconnection-wide congestion studies conducted by WECC. Tacoma notes that ColumbiaGrid is considering the

[314] *E.g.*, APPA, Arkansas Commission, California Commission, East Texas Cooperatives, Entegra, NCPA, CREPC, Southwestern Coop, TDU Systems, and WIRES.

[315] *E.g.*, American Transmission, EEI, Progress Energy, and Southern.

[316] Entegra, however, replied to Southern's assertion that congestion studies can be misleading, stating that congestion studies did not need to be misleading, and were, on the contrary, necessary for customers to assess the costs of managing versus eliminating congestion.

[317] *E.g.*, Imperial, MidAmerican, Nevada Companies, NorthWestern, Pinnacle, Salt River, SWAT, WestConnect, and Xcel.

[318] Others assert that the DOE studies will be useful but not necessarily duplicative of the congestion study principle. *E.g.*, APPA and Salt River.

[319] Bonneville agrees that the costs of congestion itself are not readily available to transmission providers and that customers are better positioned to determine this.

services it can offer in congestion assessment at the sub-regional level in the Northwest. Other commenters, such as California Commission, Salt River, and Seattle, support a congestion studies requirement but believe it should not be required annually but rather biennially or triennially.

534. In the Eastern Interconnection, RTOs and ISOs, and entities in RTOs and ISOs, believe congestion studies are not needed where LMP markets are in place or are satisfied by RTO or ISO studies.[320] Entergy argues that the congestion studies that will be performed by its independent coordinator of transmission should meet this requirement.

Determining ''Significant and Recurring'' Congestion

535. A variety of commenters provide suggestions as to what constitutes ''significant and recurring'' congestion. TDU Systems believe that there should be a presumption of congestion if a transmission provider posts zero ATC. TDU Systems, APPA, and Bonneville believe that other indications of significant and recurring congestion include the need for frequent generation redispatch, frequent curtailments for reasons other than force majeure, and repeated denials of requests for firm transmission service. California Commission and CREPC suggest a similar approach based on a comparison of ATC and schedules with historical flows and an assessment of denied requests, but emphasize that the process should be forward-looking as well.

536. APPA suggests the use of metrics to measure congestion (*e.g.*, reporting on all congestion costs that exceed five percent of base energy costs and five percent of the hours in a season). California Commission also suggests the use of metrics, but cautions that there may be East-West differences. Sacramento stresses that such metrics should depend on whether the system being studied uses LMP or physical rights. In its view, financial metrics are most useful in LMP markets, while congestion in physical markets should be determined by paths that have been derated by a material percent of their nominal rating over a certain number of hours in a season.

537. Santa Clara suggests that significant and recurring congestion exists when congestion costs over a given path during the high use season approach or exceed the depreciation plus other fixed costs on the new facilities that would eliminate congestion on the path. Additionally, Santa Clara emphasizes that if, redispatch is necessary on an ongoing basis, this should be taken as an indication that new facilities need to be built.

538. New York Commission urges the Commission to utilize NYISO's process for measuring historical congestion—defined as the short-run production (*i.e.*, dispatch) costs that could be avoided by system enhancements, as this represents the savings to society compared to the cost to society of investing in the system enhancement. New York Commission also cautions the Commission against using analyses focused on the impacts of transmission investments on wholesale energy prices, because these energy price impacts may be temporary and offset by changes in generation investments. TDU Systems and Old Dominion stress that in PJM significant and recurring congestion should be based on total gross congestion and not the much smaller and unrealistic measure of unhedgeable congestion, as this masks the economic reality that congestion itself has an economic cost.[321]

539. The Organizations of MISO and PJM States do not believe the Final Rule should address criteria for determining significant and recurring congestion, but should require each transmission provider to file criteria for inclusion and cost responsibility for upgrades that are included in the transmission plan to remedy congestion.

540. Seattle asserts that current OASIS standards do not support consistent tracking of service denials and that this inhibits the evaluation of congestion. Seattle also points out that the costs of congestion may be difficult to quantify because reliability dispatch is a reactive tool used only after service requests have been denied and prescheduled limits imposed and, therefore, foregone transactions will not be known to the transmission provider.

541. Ohio Power Siting Board asserts that distributed generation, demand response, and new technologies should be available to relieve congestion until longer-term solutions can be implemented.

Commission Determination

542. The Commission adopts the NOPR proposal and retains a congestion study principle as part of the Final Rule's transmission planning process; however, we modify and clarify the principle in certain important respects in response to the comments received. At the outset, we wish to clarify that our primary objective in adopting this principle is to ensure that the transmission planning process encompasses more than reliability considerations. Although planning to maintain reliability is a critical priority, it is not the only one. Planning involves both reliability and economic considerations. When planning to serve native load customers, a prudent vertically integrated transmission provider will plan not only to maintain reliability, but also consider whether transmission upgrades or other investments can reduce the overall costs of serving native load. Such upgrades can, for example, reduce congestion (redispatch) costs or integrate efficient new resources (including demand resources) and new or growing loads. Thus, to represent good utility practice and provide comparable service, the transmission planning process under the *pro forma* OATT must consider both reliability and economic considerations. The purpose of this principle is to ensure that the latter is considered adequately in the transmission planning process.

543. Some commenters argue that economic upgrades should be considered only in the context of individual requests for service under the *pro forma* OATT. The Commission disagrees. The process for addressing individual requests for service under the *pro forma* OATT is adequate for customers who request specific transmission rights to purchase power from a particular resource in a particular location during a defined time period. However, it does not provide an opportunity for customers to consider whether potential upgrades or other investments could reduce congestion costs or otherwise integrate new resources on an aggregated or regional basis outside of a specific request for interconnection or transmission service. It thus limits, for example, groups of customers from considering more comprehensive solutions to transmission congestion, including investment in demand response. It also limits multiple LSEs from considering, on a more aggregated basis, whether particular upgrades may represent the most economic means of integrating new generation resources (*e.g.*, wind resources) located in a common area that could be accessed by many customers. The Commission believes such coordinated studies can, for system planning purposes, be more beneficial than studies performed on a request-by-request basis. We also find that they are consistent with the requirement to provide comparable service.

[320] *E.g.*, Allegheny, FirstEnergy, Indianapolis Power, and PSEG.

[321] *See also* Indicated Parties Reply.

Transmission providers are not limited, in serving native load customers, to studying potential transmission upgrades only in the context of specific requests for service under the *pro forma* OATT.

544. Some transmission providers appear to object to this principle because they fear that an obligation to study potential upgrades is equivalent to an obligation to fund or build such upgrades. We clarify that this is not the intent of this principle. There is a difference between a planning process that is coordinated and open and one that dictates construction and cost responsibility. Both considerations are important, but, as we explain above, they are distinct. The purpose of this principle is to ensure that customers may request studies that evaluate potential upgrades or other investments that could reduce congestion or integrate new resources and loads on an aggregated or regional basis (*e.g.*, wind developers), not to assign cost responsibility for those investments or otherwise determine whether they should be implemented. The issue of cost allocation is addressed in Principle No. 9 below.

545. The Commission also disagrees with the contentions of certain RTOs or ISOs that they need not comply with this principle. Although RTO and ISO planning processes tend to be more open and coordinated than the processes used by vertically-integrated transmission providers, this does not mean that RTO or ISO processes adequately address, in all circumstances, investments that are primarily economic in nature. When many RTO and ISO planning processes were created, they focused primarily on system enhancements necessary to maintain reliability. However, in recent years, as congestion has increased and generation reserve margins have declined, many RTOs and ISOs have taken increasingly progressive steps to identify investments that could reduce congestion and/or integrate new resources. For example, we recently approved a proposal by PJM to significantly enhance its RTEP planning process.[322] We applaud these efforts as consistent with the direction of the reforms adopted herein. However, we decline to provide a blanket exception for RTOs and ISOs. Each RTO or ISO must show that its planning process is consistent with or superior to the requirements of the Final Rule in all respects.

546. Some commenters express concern that this principle may result in costly congestion studies that are of little interest or value to customers. Our intent is not to impose a costly study requirement that is unrelated to the real-world concerns of consumers. In the NOPR, we sought comment on whether specific metrics (*e.g.*, zero ATC or TLR frequency) should be used to trigger the congestion study requirement. After considering the comments on this topic, we do not believe that any single metric, or group of metrics, is adequate for that purpose. Relying on discrete metrics in this instance would risk both over- and under-inclusiveness—*i.e.*, triggering too many studies, thereby imposing cost burdens on transmission providers that are not appropriate, or triggering too few studies, thereby omitting important studies that could help customers identify cost-effective solutions to congestion. Additionally, we direct transmission providers, in consultation with their stakeholders during development of their Attachment K compliance filings (as discussed above), to develop a means to allow the transmission provider and stakeholders to cluster or batch requests for economic planning studies so that the transmission provider may perform the studies in the most efficient manner. We will also require the requests for economic planning studies, as well as the responses to the requests, be posted on the transmission provider's OASIS or Web site, subject to confidentiality requirements.

547. The Commission will modify the principle to allow customers to choose the studies that are of the greatest value to them. Specifically, we are modifying the principle to require that stakeholders be given the right to request a defined number of high priority studies annually (*e.g.*, five to ten studies)[323] to address congestion and/or the integration of new resources or loads. The intent of this approach is to allow customers, not the transmission provider, to identify those portions of the transmission system where they have encountered transmission problems due to congestion or whether they believe upgrades and other investments may be necessary to reduce congestion and to integrate new resources. The customers should be able to request that the transmission provider study enhancements that could reduce such congestion or integrate new resources on an aggregated or regional basis without having to submit a specific request for service. This approach ensures that the economic studies required under this principle are focused on customer needs and concerns, not administratively determined metrics that may bear no necessary relation to those concerns. Once such studies are requested, the transmission provider would conduct the studies, including appropriate sensitivity analyses, in a manner that is open and coordinated with the affected stakeholders. The cost of the defined number of high priority studies would be recovered as part of the overall pro forma OATT cost of service.[324] By limiting this principle to a defined number of high priority studies annually, we are not precluding stakeholders from requesting additional studies. However, to provide appropriate financial incentives, the stakeholder(s) requesting these additional studies would be responsible for paying the cost of such studies.

548. We also will modify this principle with respect to the scope of the studies being performed. The Commission proposed in the NOPR that the studies address ''significant and recurring congestion.'' However, the Commission also sought comment on whether, in addition, the study process should address upgrades associated with new generation resources and provide information needed to proactively evaluate such resources. We discuss the comments on this proposal in more detail below, but, as described therein, we agree that the study process should incorporate such considerations. We therefore modify Principle No. 8 to encompass the study of upgrades to integrate new generation resources or loads on an aggregated or regional basis. This is appropriate because congestion can limit both the efficient dispatch of existing generation resources as well as inhibit the development of new supply and demand resources. Moreover, many regions of the country must make investments in the near future to meet load growth and, accordingly, studies of the most economic means of making such investments are critically important to consumers.

549. By expanding the scope of this principle, we do not intend to supplant the existing process for individual customers to integrate new resources or loads through specific requests for

[322] *See PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,218 (2006), *reh'g pending*.

[323] The example of five to ten studies mentioned in this Final Rule is merely illustrative. We recognize that the facts of each case will be used to determine the number of high priority studies allowed under a transmission plan.

[324] This cost recovery mechanism is comparable and nondiscriminatory because the transmission provider already has the ability to include in its *pro forma* OATT rates the cost of service associated with studies performed on behalf of native load customers.

interconnection or transmission service under the *pro forma* OATT. Rather, we contemplate that any such studies conducted pursuant to this principle, as explained above, would be for purposes of planning for the alleviation of congestion through integration of new supply and demand resources into the regional transmission grid or expanding the regional transmission grid in a manner that can benefit large numbers of customers, such as by evaluating transmission upgrades necessary to connect major new areas of generation resources (such as areas that can support substantial wind generation). Specific requests for service would continue to be studied pursuant to existing *pro forma* OATT processes.

550. With respect to studying the cost of congestion, several transmission providers argue that they do not have access to information regarding generation costs either from their merchant function or unaffiliated customers. We agree that the transmission provider should be obligated to study the cost of congestion only to the extent it has information to do so. We make clear, however, that if stakeholders request that a particular congested area be studied, they must supply relevant data within their possession to enable the transmission provider to calculate the level of congestion costs that is occurring or is likely to occur in the near future. To the extent that the transmission provider's merchant function possesses such information (*e.g.*, redispatch cost information), it must provide that information to the extent necessary to conduct such studies. Providing for confidential treatment and application of the Standards of Conduct, as discussed above, will give assurance to customers that their cost and other information will not be used improperly. To that end, we direct transmission providers to clearly define the information sharing obligations placed on customers in the planning attachment to their *pro forma* OATT.

551. In response to those commenters that argue that regional congestion studies should be sufficient, we agree that regional congestion studies can be used as part of regional transmission planning processes required by this Final Rule. For example, to the extent the DOE has extensively studied congestion in certain broad areas, it is not necessary or appropriate for transmission providers to duplicate these studies. However, regional studies typically provide broad information on overall regional power flows and may not provide sufficient detail on local system conditions and congestion, such as detail on congested local facilities that may limit customer supply options, or detail on local conditions where additional service could be provided through redispatch. Moreover, although the DOE may identify areas where congestion exists or new generation may be developed, the purpose of DOE congestion studies is not to develop specific transmission system plans to remedy such congestion or integrate such resources. The DOE studies are therefore not a substitute for a more open and coordinated planning process to address specific upgrades that could reduce congestion or integrate new resources and loads. We therefore require each transmission provider to comply with the revised economic planning studies principle in this Final Rule both as to its own transmission system and as to the regional planning process described above.

i. Cost Allocation for New Projects

552. In the NOPR, the Commission asked for comment on whether there should be a requirement for public utilities to develop cost allocation principles to address the recovery of costs associated with new transmission projects. In particular, the Commission asked whether the development of specific cost allocation principles would provide greater certainty and hence support the construction of new infrastructure or whether cost allocation is better handled on a case-by-case basis.

Comments

553. Several commenters express concern that the Final Rule not reopen cost allocation principles in RTOs and ISOs or in the OATTs of vertically integrated transmission providers.[325] Duke argues that the Final Rule should not address cost allocation for new transmission at all, stating that transmission pricing should be evaluated in a separate proceeding. Other commenters agree that cost allocation issues should be handled on a case-by-case basis.[326]

554. Some commenters urge the Commission to define cost allocation principles in this proceeding.[327] For example, E.ON believes that the cost of upgrades should be directly allocated to parties benefiting from an expansion and proposes that the host transmission owner should coordinate and be responsible for obtaining funding. Many transmission customers, however, support rolled-in cost recovery for network upgrades.[328] TDU Systems ask the Commission to clarify that direct assignment of facility upgrade costs only applies to point-to-point service, unless it is being used for the delivery of designated network resources to serve network load. If direct assignment is retained, TDU Systems suggest the Commission consider standardizing directly assignable facilities on a regional basis and stress that the critical factor is comparability. TAPS suggests ''regional'' cost-spreading for backbone high voltage facilities and criticizes participant funding because it encourages would-be beneficiaries to wait and hope that others will step forward first.

555. Old Dominion emphasizes the need for cross-border transmission cost allocation mechanisms. In joint projects, Salt River emphasizes that it is inconsistent with an open season approach to assign benefits to a party and then assign cost responsibility beyond what the project participant would voluntarily assume based on the subscription rights received. Both Bonneville and TVA believe that cost allocation principles should be based on a determination of beneficiaries and cost causation. New Mexico Attorney General stresses that cost recovery for construction of transmission intended for wholesale or market transactions should not be allocated to native load. NCPA states that it would expect some Commission deference to recovery of costs of projects identified in a truly collaborative process.

556. At the October 12 Technical Conference, PJM stated that the Commission should provide generic guidance on what would be acceptable regarding cost allocation, though Progress Energy did not favor putting a cost allocation approach in the *pro forma* OATT, as modified by the Final Rule. National Grid expressed the view that the Commission would need to address cost allocation generally, arguing that cost allocation solely on a project-by-project basis is inefficient.

Commission Determination

557. The Commission finds, after considering the comments, that it is appropriate to include a specific principle regarding cost allocation. The manner in which the costs of new transmission are allocated is critical to the development of new infrastructure. Transmission providers and customers cannot be expected to support the

[325] *E.g.,* Duke, EEI, ELCON, ISO/RTO Council, MISO Transmission Owners, SCE, and Southern.

[326] *E.g.,* APPA, Arkansas Commission, PGP, Santee Cooper, Southwestern Coop, and Sacramento.

[327] *E.g.,* E.ON, National Grid and WIRES.

[328] *E.g.,* AWEA, NCEMC, NCPA, NRECA, Seattle, and TDU Systems.

construction of new transmission unless they understand who will pay the associated costs. We therefore find that, for a planning process to comply with the Final Rule, it must address the allocation of costs of new facilities.

558. The Commission emphasizes, however, that we are not modifying the existing mechanisms to allocate costs for projects that are constructed by a single transmission owner and billed under existing rate structures. Our intent is not to upset existing cost allocation methods applicable to specific requests for interconnection or transmission service under the *pro forma* OATT. The cost allocation principle discussed herein is intended to apply to projects that do not fit under the existing structure, such as regional projects involving several transmission owners or economic projects that are identified through the study process described above, rather than through individual requests for service. We will not impose a particular allocation method for such projects, but rather will permit transmission providers and stakeholders to determine their own specific criteria which best fit their own experience and regional needs. The proposal should identify the types of new projects that are not covered under existing cost allocation rules and, therefore, would be affected by this cost allocation principle.

559. Although the Commission does not prescribe any specific cost allocation method in the Final Rule, we believe some overall guidance is appropriate. Our decisions regarding transmission cost allocation reflect the premise that ''[a]llocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science.'' [329] We therefore allow regional flexibility in cost allocation and, when considering a dispute over cost allocation, exercise our judgment by weighing several factors. First, we consider whether a cost allocation proposal fairly assigns costs among participants, including those who cause them to be incurred and those who otherwise benefit from them. Second, we consider whether a cost allocation proposal provides adequate incentives to construct new transmission. Third, we consider whether the proposal is generally supported by State authorities and participants across the region.

560. These three factors are interrelated. For example, a cost allocation proposal that has broad support across a region is more likely to provide adequate incentives to construct new infrastructure than one that does not. The states, which have primary transmission siting authority, may be reluctant to site regional transmission projects if they believe the costs are not being allocated fairly. Similarly, a proposal that allocates costs fairly to participants who benefit from them is more likely to support new investment than one that does not. Adequate financial support for major new transmission projects may not be obtained unless costs are assigned fairly to those who benefit from the project.

561. These factors are particularly important as applied to the economic upgrades discussed above—*e.g.*, upgrades to reduce congestion or enable groups of customers to access new generation. As a general matter, we believe that the beneficiaries of any such project should agree to support the costs of such projects. However, we recognize that there are free rider problems associated with new transmission investment, such that customers who do not agree to support a particular project may nonetheless receive substantial benefits from it. In the past, different regions have attempted to address such issues in a variety of ways, such as by assigning transmission rights only to those who financially support a project or spreading a portion of the cost of certain high-voltage projects more broadly than the immediate beneficiary/supporters of the project. We believe that a range of solutions to this problem are available. We therefore continue to believe that regional solutions that garner the support of stakeholders, including affected State authorities, are preferable. Moreover, it is important that each region address these issues up front, at least in principle, rather than having them relitigated each time a project is proposed. Participants seeking to support new transmission investment need some degree of certainty regarding cost allocation to pursue such investments.

3. Additional Issues Relating to Planning Reform

a. Independent Third Party Coordinator

562. In the NOPR, the Commission acknowledged that an independent third party coordinator would provide benefits for transmission planning, but did not propose to require independence. Noting that independence could take many forms, the Commission sought comment on the level of independence that could provide benefits and the institutions that could offer such independence.

Comments

563. Overall comments on the use of an independent third party to oversee or coordinate the planning process range from those who believe it is not needed to those who feel that it should be required rather than merely encouraged. Arguing against the need for an independent coordinator, South Carolina E&G does not believe an independent third party is either necessary or desirable. Arguing in favor of an independent coordinator, EPSA strongly supports independent oversight and believes that third party oversight will be necessary in non-RTO areas, particularly where transmission providers have conducted non-transparent processes.[330] Most commenters fall somewhere between these two positions, finding potential benefits in independence but concurring with the proposal not to mandate it.

564. Several public utility commenters acknowledge the potential benefits of using an independent coordinator and believe the Commission should encourage it.[331] National Grid, for example, finds it difficult to see how a non-independent transmission provider would be able to manage confidential information in a manner fair to all stakeholders and recommends finding independent administration of planning ''superior to'' non-independent administration. Other commenters note only that independence can be beneficial or suggest that the Commission be open to independent third parties when offered.[332] Progress agrees there can be benefits, but does not believe an independent coordinator is needed to ensure confidence.

565. EEI argues against an independence requirement, seeing no need to require non-RTO/ISO transmission providers to engage independent third parties to oversee the planning process.[333] EEI believes the

[329] *Colorado Interstate Gas Co.* v. *FPC,* 324 U.S. 581, 589 (1945).

[330] *See also* AWEA, Arkansas Commission, Old Dominion, and Project for Sustainable FERC Energy Policy. Old Dominion stresses that even in RTOs, the transmission owners may have the ability to exercise market power and, therefore, the market monitoring unit should have the requisite independence and authority to investigate and address undue influence.

[331] *E.g.,* National Grid, PPL, Constellation, and Tacoma.

[332] *E.g.,* APPA, Bonneville, California Commission, Duke, Indianapolis Power, NCEMC, NorthWestern, Progress Energy, CREPC, Sacramento, Seattle, and TDU Systems. Some public power entities, such as APPA, NRECA, and TDU Systems are concerned with ensuring that the costs of an independent coordinator do not outweigh the benefits.

[333] TVA believes that the levels of independence practiced in NERC and NAESB and the implementation and administration of those

planning processes proposed in the NOPR are adequate without third party oversight and maintains that requiring third party coordination could add another layer of administration, might encroach on State authority, and could create the possibility that the transmission provider would lose control of the transmission plan. EEI however also notes that the Commission could require independent oversight in circumstances where a transmission planner has failed to implement the principles or has engaged in undue discrimination in planning for customer needs.

566. The consensus at the October 12 Technical Conference was generally supportive of the potential benefits of an independent facilitator, but not supportive of a mandate. There was general support for the idea that an independent facilitator can assist with handling sensitive information and provide confidence that analysis of information would be fair, although several participants stated that sufficient trust and confidence could be obtained without an independent facilitator.

Commission Determination

567. The Commission adopts the NOPR proposal to not require the use of an independent third party coordinator at this time. We agree that there are benefits to be gained from independent third party oversight, as cited by commenters, such as the ability to manage confidential information and the ability to ensure equitable treatment of all viewpoints in planning. We therefore encourage transmission providers and their customers and other stakeholders to explore aspects of planning where the use of an independent coordinator would be beneficial and to incorporate those aspects in their planning process compliance filings.

568. It is, however, possible to comply with the principles without the use of an independent third party. We expect the transmission plans themselves to be developed under an open process that includes coordination among each transmission provider, its customers, other stakeholders, and its neighbors. A transmission provider will need to demonstrate to us in a compliance filing that the plan meets the principles, including providing a dispute resolution process. We believe that an open, transparent planning process, with meaningful coordination and dispute resolution, will provide a sufficient basis for customers to identify and raise meaningful concerns if a plan does not treat similarly-situated customers in a comparable manner, where planning appears to be conducted in a discriminatory manner, or in other instances where the independence of planning may be in question. If disputes do arise in these areas and cannot be resolved consensually, we are available to either encourage a consensual resolution (*e.g.*, by use of the Dispute Resolution Service) or resolve them ourselves if a complaint is filed.

b. State Commission Participation

569. In the NOPR, the Commission strongly encouraged the participation of State commissions and other State agencies in the coordinated planning process, particularly with regard to regional planning. The Commission sought comment on how best to accommodate effective State participation.

Comments

570. All commenters addressing the question of State participation agree that states have an important role in transmission planning, but there were only limited comments recommending specific processes to encourage State participation. Supporters of State participation generally believe that it can assist in obtaining siting approval and in cost recovery. ISO/RTO Council and individual RTOs and ISOs point to their current processes for including states in their region in the planning process. Noting the local benefits that can derive from interstate transmission projects, American Transmission supports collaborative efforts among states such as the Organization of MISO States. However, American Transmission and other commenters suggest that the Commission defer to the states to determine how they participate in the planning process.[334]

571. Allegheny believes it should be the responsibility of the transmission provider to maintain good communication with State commissions. Nevada Companies assert that the real question the Commission should be posing is how to coordinate the State jurisdictional role in transmission planning and construction and the obligations imposed by the Commission on transmission providers, so that the system of coordination does not put transmission providers in the middle between conflicting State and Commission requirements. Moreover, Santa Clara notes that some State commissions do not represent all energy consumers, since they are charged only with regulating public utilities, and could be conflicted and disinclined to act in the best interests of entities not under their jurisdiction.

572. NARUC supports active State commission participation in both RTO and non-RTO markets.[335] NARUC asks that the Commission clarify that its planning proposals assume that the results of State commission planning decisions relating to retail load will be incorporated into the planning process rather than subject to further review. NARUC and New Mexico Attorney General also ask for clarification that joint planning will allow for communications between resource and transmission planners for the purpose of developing State-required resource plans and that this will not be considered a violation of the Standards of Conduct. PNM–TNMP and Southern support the NARUC position in their reply comments.

573. New York Commission wants to ensure that the Commission's planning responsibilities cover only transmission that serves a bulk power system function.[336] Florida Commission believes that it already has direct oversight of grid planning and related issues, through among other things its participation in the FRCC planning process and review of the annual Ten Year Site Plan. Seattle does not believe that any additional requirements are needed for State commission participation. Other commenters are concerned that State policy goals, such as California's Renewable Portfolio Standard, be included in the coordinated planning required by the Final Rule.[337] NARUC and California Commission also discuss State staff and fiscal constraints on participation, and California Commission suggests that the Commission consider a tariff rider to fund State participation.

Commission Determination

574. The Commission strongly encourages State participation in the transmission planning process and expects that all transmission providers will respect states' concerns, such as retail resource needs, in the planning

standards by the regional entitities (such as SERC) are adequate and appropriate.

[334] *E.g.*, American Transmission, Duke, and Progress Energy.

[335] Similar views are expressed by APPA, Arkansas Commission, Bonneville, California Commission, NCEMC, NYAPP, and CREPC. NYAPP, however, asks the Commission to be vigilant in not allowing State commissions improper control over the planning process.

[336] NYAPP, on the other hand, urges the Commission to require planning for all transmission facilities, not just bulk power facilities.

[337] *E.g.*, AWEA, California Commission, and Project for Sustainable FERC Energy Policy.

process.[338] As with any other interested stakeholder, we emphasize that planning must be coordinated with relevant State regulators (including city councils, local siting boards, and other agencies) that wish to participate in the transmission provider's planning process. We will not prescribe a particular level of State participation, but rather encourage states to determine their own level of participation, consistent with applicable State law.[339] We stress that State determinations with respect to retail load will not be second-guessed, but that once those determinations are incorporated into the transmission plan, the transmission planning principles will apply (*e.g.*, for purposes of determining whether similarly-situated customers are treated comparably).

575. Just as we intend to coordinate with State regulators and other agencies, we also encourage those parties to collaborate amongst themselves as well, particularly regionally, in order to reach agreement on how best to review and approve new transmission facilities that are the product of the coordinated and regional planning process required by this Final Rule. We intend to defer to such agreements between State regulators and other agencies in a given region as appropriate. We are, moreover, sensitive to concerns, such as Allegheny's, about the overlapping nature of regulatory jurisdiction over planning matters. We believe the planning principles in this Final Rule will help alleviate this concern by facilitating coordination through open, transparent planning and enhanced exchange of information. We also understand Santa Clara's concern that certain State regulators do not represent all energy consumers in some states; however, we do not believe this detracts from the significant interest that State regulators and other agencies have with regard to transmission planning for their State and region.

c. Flexibility in Implementation and Examples of Compliant Processes

576. In the NOPR, the Commission sought comment on how much flexibility the transmission provider should be given in implementing the principles and requested examples of transmission planning processes that comply with the proposed principles.

Comments

577. Commenters generally favor flexibility and urge the Commission not to be too prescriptive regarding how the planning processes must satisfy the planning principles. Many entities in the Western Interconnection cite the overall WECC process as largely compliant with the principles. Nevada Companies notes that the WECC process works well under the existing *pro forma* OATT, so that few changes should be required to implement the proposal. In the East, Progress Energy and Duke cite NC Transmission Planning as an example of an effective planning process that generally meets the principles.

578. Constellation agrees with providing flexibility, but believes the Commission should strongly encourage transmission providers to model their compliance filings after existing processes, such as those in RTOs and ISOs. ISO/RTO Council and all individual RTOs and ISOs argue that their processes are generally compliant and should not be disturbed. Transmission providers in RTOs and ISOs generally support this position.[340]

579. Some entities believe that flexibility should be permitted in order to deal with regional variations, but that individual transmission providers should have limited flexibility in implementing the planning process.[341] Some commenters simply state that regional flexibility should be permitted, without further elaboration.[342] Other commenters urge the Commission to limit both regional and local flexibility.[343]

580. NRG argues that system planning models should reflect economic dispatch to facilitate efficient utilization and also argues in favor of requirements for specific criteria on the treatment of system overloads and contingencies. AWEA proposes a specific regional planning protocol patterned off the ''Collaborative Governance'' model developed during mediation for the Southeast RTO in Docket No. RT01–100.

581. In reply to commenters arguing in favor of less flexibility, Indianapolis Power maintains that its experience in MISO shows that flexibility is needed, citing the wide variations within the MISO footprint and the difficulties experienced in planning for a single large region. MidAmerican opposes the NRG proposal for regional modeling standards, as well as the AWEA proposal for a regional planning protocol, as too burdensome. Exelon expresses general agreement with the EEI position on flexibility, but states that planning processes outside RTOs do not presently meet the NOPR's requirements. Exelon states planning processes outside RTOs should follow the planning direction of RTOs like PJM.

Commission Determination

582. Although we allow flexibility in the development of a coordinated and regional planning process, the Commission will carefully review transmission planning compliance filings to ensure that each planning process is consistent with the planning principles and other requirements in this Final Rule. We encourage transmission providers to give consideration to existing planning processes, such as those already implemented by ISOs or RTOs, or those proposed by AWEA, as they work with their customers and other stakeholders to develop a transmission planning process that complies with the Final Rule. The Commission makes clear, however, that we do not endorse any specific existing process as a model for all transmission providers.

d. Recovery of Planning Costs

583. In the NOPR, the Commission recognized that participants in the planning process must be assured of recovery of their costs incurred in the planning process, as well as assured that the costs will be borne equitably by all parties benefiting from the process. The Commission also sought comment on whether there should be a principle or requirement regarding cost recovery and allocation associated with funding the regional planning requirement.

Comments

584. Public utility commenters generally support the principle that costs should be borne by the beneficiaries of the process. EEI agrees, but argues that the Commission should not establish a specific cost basis for recovery, and several other commenters concur.[344] NorthWestern and PSEG support a cost causation principle for

[338] As noted above, we expect the concerns of NARUC and others that the application of the Commission's Standards of Conduct are inhibiting State resource planning will be addressed in the rulemaking proceeding on the Standards of Conduct in Docket No. RM01–7–000. See supra note 257.

[339] We also recognize that there are concerns about how State regulators and other agencies will recover the costs associated with their participation in the planning process. As discussed below, we direct transmission providers to propose a mechanism for cost recovery in their planning compliance filings. These proposals should include relevant cost recovery for State regulators, to the extent requested.

[340] *E.g.*, Allegheny, Duke, and National Grid.

[341] *E.g.*, APPA, East Texas Cooperatives, Seattle, and TDU Systems.

[342] *E.g.*, Bonneville, Salt River, PJM, and TVA.

[343] *E.g.*, Arkansas Municipal, Project for Sustainable FERC Energy Policy, and Southwestern Coop.

[344] *E.g.*, Duke, Indianapolis Power, MidAmerican, Progress Energy, PSEG, South Carolina E&G, and SPP.

allocation of costs of planning, and Southern argues that entities that request any transmission sensitivity studies should bear the costs of those studies.

585. There is general agreement with the principle that costs should be recoverable, and some public utilities request that the Commission clarify that all planning costs not directly assigned are recoverable through transmission provider transmission rates.[345] Other commenters believe that the parties in the planning process should determine how planning costs should be allocated and funded. APPA urges simplicity, the avoidance of double collecting (*e.g.*, LSEs should not have to pay through both transmission rates and individually) and stresses the need to assess costs based on size and assets. Other comments are consistent with equitable allocation of planning costs.[346]

Commission Determination

586. We will not propose a specific method for recovery and allocation of planning costs in this Final Rule. We recognize, however, the importance of planning cost recovery and will require transmission planning processes to provide a mechanism for recovery of costs. We direct transmission providers to work with other participants in the planning process, as part of the collaborative process described above, to develop their cost recovery proposals in order to determine whether all relevant parties, including State agencies, have the ability to recover the costs of participating in the planning process. Transmission providers should also consider whether mechanisms for regional cost recovery may be appropriate, such as through agreements (formal or informal) to incur and allocate costs jointly. The Commission will consider resulting cost recovery proposals, including special riders to transmission rates, with an eye toward encouraging the broadest participation in the planning process possible.

e. Open Season for Joint Ownership

587. In the NOPR, the Commission expressed its belief that an open season to allow market participants to participate in joint ownership, particularly for large new transmission projects, could stimulate grid investment and ensure that all customers have the ability to participate in new projects on a nondiscriminatory basis. The Commission sought comment on whether to include such a requirement and, if so, what conditions or limitations should be associated with it.

Comments

588. As a general matter, a number of commenters believe that the planning process should include a mandate to construct identified upgrades or otherwise hold transmission providers accountable for carrying out the plan.[347] EEI and others argue that such a mandate would go beyond planning and result in providers giving up control of their systems. In their replies, LPPC and Sacramento assert that the decision to build facilities and to carry out transmission plans must rest with transmission providers and State authorities and that, in any event, it is unclear that the Commission has the authority to compel construction pursuant to regional transmission plans. At the October 12 Technical Conference, there was considerable discussion of the obligation to build and its relationship to the planning process proposed in the NOPR.

589. While not necessarily opposed to voluntary joint ownership arrangements in general, many commenters oppose the idea of mandated open seasons.[348] EEI provides a representative summary of the arguments of those opposed to open seasons. First, EEI argues that the Commission does not have the authority to order joint ownership and that joint ownership could interfere with State siting authority. It maintains that the instances where the Commission can order transmission construction are very limited and do not extend to the authority to order joint ownership.[349] Second, EEI argues that joint ownership will not provide the benefits cited by the Commission, stating that there is ample evidence that joint ownership of transmission lines is not needed to achieve economies of scale in construction. In its view, the level of transmission investment is currently increasing and joint ownership should not be expected to create additional sources of transmission investment. Third, EEI contends that prospective joint owners mistakenly believe they will not be subject to the same requirements as Commission-jurisdictional owners and urge the Commission to make clear that both jurisdictional and nonjurisdictional owners would be subject to the same requirements for service over jointly-owned facilities. If the Commission were to order joint ownership, Duke argues that it must condition such ownership by a nonjurisdictional entity on that entity filing a safe harbor OATT ensuring reciprocal open access by that joint owner.

590. Tacoma notes that ColumbiaGrid includes a mechanism for small users to participate in transmission projects in the proposal it is considering for its planning process. Xcel supports adopting the open season concept as an option in joint planning requirements. Though it does not completely oppose the principle, MidAmerican sees significant practical problems in developing and implementing an open season proposal and regards the open season idea as premature. Others generally support allowing for open seasons and joint ownership, but also do not believe they should be mandated.[350]

591. A number of other commenters, however, support requiring open seasons as a method of ensuring that identified upgrades are constructed. ELCON is strongly in favor, stating that open seasons for joint ownership is an ''idea whose time has come'' and expressing frustration that the Commission has not already acted on this proposal. FMPA argues that joint ownership will aid in providing additional capital for transmission projects. TDU Systems urge the Commission to require transmission providers, including RTOs and ISOs, to hold open seasons.[351] Joined by Arkansas Commission, TDU Systems argue that open seasons should not be limited to large projects. PGP supports open seasons when providers do not voluntarily agree to add capacity based on the results of the transmission plan. TDU Systems cite the Neptune and

[345] *E.g.*, Southern and South Carolina E&G.

[346] *E.g.*, Bonneville, NRECA, and CREPC.

[347] *E.g.*, APPA, East Texas Cooperatives Reply, FMPA, NCPA, TAPS, TDU Systems, Utah Municipals, and WIRES.

[348] *E.g.*, Allegheny, American Transmission, Constellation, New York Transmission Owners, MidAmerican, Duke, EEI, Entergy, FirstEnergy, MISO, National Grid, Northeast Utilities, NorthWestern, Progress Energy, PSEG, South Carolina E&G, SCE, Southern, SPP, Tacoma, Tucson, and Xcel.

[349] APPA, FMPA, TAPS, and TDU Systems, however, point to various sources of authority on which the Commission could rely to mandate open seasons and joint ownership, such as: To remedy undue discrimination under FPA sections 205 and 206; to carry out FPA section 214(b)(4)'s requirement to facilitate the planning and expansion of transmission facilities to satisfy the needs of load-serving entities; as a condition of market-based rate authority, FPA section 203 approval, or transmission rate incentives under FPA section 219; and under the permitting regulations promulgated under FPA section 216(c)(2)(B) dealing with backstop siting authority.

[350] *E.g.*, Bonneville, California Commission, and CREPC. Bonneville stresses that any jointly-owned facilities should have a single operator.

[351] Similar comments were made by APPA, Arkansas Commission, FMPA (includes a legal analysis in an attachment), NCPA, MISO/PJM States, Santa Clara, Southwestern Coop, TANC, and TAPS.

Cross-Sound Cable projects, where regulated utilities failed to provide solutions despite the need for expansion of the system in those regions. Seattle argues that voluntary joint ownership of projects should not be contingent upon an open season requirement. TANC points to current joint ownership arrangements in the Western Interconnection. Sacramento likewise notes that the joint planning and ownership process in the Western Interconnection has been a success, but asks the Commission to make clear that physical rights set asides are available in CAISO to accommodate non-LMP co-owners.

592. On reply, EEI, Entergy, and Southern repeat arguments against joint ownership and open seasons. EEI replies that FMPA's claim that joint ownership will result in increased investment is not based on fact and will not increase access. In its reply, TDU Systems states that joint ownership would not, as argued by EEI, infringe on State siting, as states would retain this authority over the jointly-developed project. APPA also stresses that its members have fewer difficulties obtaining service where joint ownership is permitted. In their replies, Lassen, Santa Clara, and TANC argue that the Commission should not, as suggested by Duke, condition the participation of a nonjurisdictional entity in a jointly-owned project on that entity filing a safe harbor OATT, as public power entities use the capacity they need and sell the rest whether or not they have a safe harbor OATT on file. However, TAPS asks on reply that access to jointly-owned facilities be available through a *pro forma* OATT. Participants at the October 12 Technical Conference expressed both support for joint ownership, as well as caution. National Grid states that it has had good success with joint ownership, but that jointly-owned projects are more complicated and can take longer to develop.

Commission Determination

593. The Commission believes there are benefits to joint ownership of transmission facilities, particularly large backbone facilities, both in terms of increasing opportunities for investment in the transmission grid, as well as ensuring nondiscriminatory access to the transmission grid by transmission customers. The comments received in response to the NOPR support the notion that joint ownership can provide these benefits in many cases. For example, as TDU Systems note, the Neptune and Cross-Sound Cable projects have resulted in significant amounts of new transmission capacity in regions facing chronic constraints. We encourage joint ownership for other large backbone transmission upgrades included in the transmission plan developed by the planning process required by this Final Rule.[352]

594. We acknowledge, however, that joint ownership can increase the complexity of planning and developing a transmission project and are sensitive to concerns that formal open seasons can add to that complexity. We therefore do not mandate open season procedures to allow market participants to participate in joint ownership. We recognize that there may be reasons, given the complexity of the transmission grid and changing conditions of supply and demand for power, why any given facility identified in a transmission plan may not ultimately be constructed. Consequently, our planning reforms do not include an obligation to construct each facility identified in the plan, whether individually or through joint ownership mechanisms. At the same time, the Commission agrees that joint ownership may be useful in certain situations and encourages transmission providers and customers alike to consider the use of open seasons to realize construction of upgrades identified in the planning studies. If a transmission provider declines to construct an identified upgrade, we also encourage customers and third parties to consider, either individually or jointly, development and ownership of a project to the extent consistent with applicable State law.

f. Specific Study Processes Beyond Reliability and Congestion Reduction

595. In the NOPR, the Commission sought comment on whether there should be a specific study process to identify opportunities to enhance the grid for purposes beyond maintaining reliability or reducing current congestion. Such a study process could allow interested entities, including State resource agencies and others, to request the transmission provider to model grid upgrades needed to accommodate the construction of new resources and provide information needed to proactively evaluate such resources. The Commission expected that such studies would not conflict with State prerogatives, but rather would provide states with better information to evaluate all relevant resource options.

[352] As the Commission stated in Order No. 679–A, ''[t]he Commission will look favorably on incentive requests that include public power joint ownership.'' Order No. 679–A at P 102.

Comments

596. Most transmission provider commenters favor providing for study of some grid enhancement beyond reliability and congestion-related needs, but believe the Final Rule should not mandate a specific study process. Various commenters argue that the Commission should allow planning participants to determine details such as the scope, number, and cost responsibility for the studies.[353] MISO states that it is working on these issues, but enhancement beyond maintaining reliability or reducing congestion is a complicated subject best left to each RTO or ISO to decide.

597. Some commenters are more explicit or expansive in their recommendations. CAISO recommends that the Commission develop a policy to encourage construction of transmission lines necessary to connect renewable resources,[354] and Suez Energy NA provides similar comments about new remote generation. PJM believes the planning process should look at future congestion and building for resources not yet announced. The New Jersey Board believes that demand-side management and other solutions, such as distributed renewable generation, also should be considered. WIRES and ELCON believe all credible proposals should be studied. TAPS asserts that planning should study grid enhancements needed for new potential resources.[355] These views are consistent with the views of many of the commenters that support additional study processes.[356] TDU Systems, however, point out that planning for reliability and economics should be incorporated into the open and inclusive planning process and, therefore, a special study process should not be needed.

598. Other commenters are opposed to additional processes: South Carolina E&G does not see a need for additional studies; Southern believes additional study processes would be overly burdensome and would divert attention away from the fundamentals of prudent planning; and Bonneville notes that market participants often make requests

[353] *E.g.*, EEI, MISO, NorthWestern, PSEG, and Tacoma.

[354] Related to this, California Commission asserts that regional planning processes need to be closely linked with the resource adequacy planning processes and renewable energy portfolio standards on the State level.

[355] EEI replies in opposition to TAPS' assertions that planning should address transmission for potential resources, arguing that such a requirement would be cost prohibitive and would harm users.

[356] *E.g.*, APPA, Arkansas Commission, AWEA, CREPC, Sacramento, and Seattle.

for expensive studies without following through on them. Santee Cooper cautions the Commission against giving license to those who would attempt to hijack the regional planning process in order to advance a generation-related agenda, and notes that the Commission's authority does not extend to generation resource adequacy.

Commission Determination

599. We believe that development of a study process for identifying opportunities for grid enhancement beyond reliability and congestion reduction has the potential to provide useful information and would generally benefit development of the transmission grid. We therefore will include such study processes within the scope of Principle No. 8. In the NOPR, that principle concerned only congestion studies, but, as modified above, it now includes studies regarding upgrades that could integrate new generation resources. We note that various commenters argued for the consideration of demand resources in development of enhancements to the transmission grid.[357] As we explain above, consideration of such resources falls within Principle No. 8, as modified by the Final Rule.

g. Level of Detail in the OATT

600. In the NOPR, the Commission sought comment on the level of detail to be required to be in the transmission provider's OATT regarding its planning process.

Comments

601. Several commenters argued that the details of the planning process should be included in the transmission providers' OATTs.[358] Seattle noted that the OATT should balance the need for detailed planning requirements with the need for regional processes to evolve.

Commission Determination

602. The Commission agrees that the transmission planning attachment to a transmission provider's OATT must include sufficient detail to enable transmission customers to understand the transmission provider's planning process. This new attachment must therefore include:

(a) The process for consulting with customers and neighboring transmission providers;

(b) The notice procedures and anticipated frequency of meetings or planning-related communications;

(c) A written description of the methodology, criteria, and processes used to develop transmission plans;

(d) The method of disclosure of transmission plans and related studies and the criteria, assumptions and data underlying those plans and studies;

(e) The obligations of and methods for customers to submit data to the transmission provider;

(f) The dispute resolution process;

(g) The transmission provider's study procedures for economic upgrades to address congestion or the integration of new resources; and

(h) the relevant cost allocation procedures or principles.

C. Transmission Pricing

1. General

603. As the Commission explained in Order No. 888, the *pro forma* OATT was designed to include primarily non-rate terms and conditions of open access non-discriminatory transmission service. Transmission providers first were required to adopt the non-rate terms and conditions of the *pro forma* OATT and then, in a subsequent filing under FPA section 205, to propose corresponding rates for service provided under their OATTs. Consistent with the focus of Order No. 888 on the non-rate terms and conditions of open access, the Commission did not propose broad reform of transmission pricing policy through the NOPR. Rather, the Commission identified in the NOPR several discrete pricing rules that it considered part and parcel of OATT service that merit reform, which we discuss in more detail later in this section. The Commission also specifically noted in the NOPR that the purpose of this rulemaking is to strengthen the *pro forma* OATT to remedy undue discrimination and not to create new market structures.

604. Despite the clear scope of this rulemaking, several commenters contend that broader ratemaking reforms should be implemented in order to remove obstacles to achieving competitive markets. Various commenters assert that rate pancaking must be eliminated in this reform, noting that the Commission has recognized in the past that pancaked rates inhibit the development of competitive markets.[359] Arkansas Municipal and TDU Systems contend that pancaked rates are particularly burdensome for customers with loads and resources on multiple transmission providers systems and those that sit essentially at or on the boundaries. TDU Systems argue that the failure to eliminate pancaked rates has caused many of the TDU Systems to spend many millions of dollars to build transmission from generation to interconnect with multiple control areas in order to avoid paying multiple wheeling charges.

605. Some of these commenters also advocate that the Commission should move towards joint rates.[360] Arkansas Municipal Power argues that moving toward joint rates outside an RTO will not only eliminate competitive barriers outside RTOs, but would reduce the disincentive to formation of new and expanded RTOs. TAPS complains that the NOPR requires regional planning, but has no provision requiring transmission providers to build facilities to support regional needs, arguing that joint rates would ease this problem. TDU Systems argue, however, that any joint rate methodology should not shift costs to other network customers, especially where surcharges are sought that might open the door to potential over-recovery by transmission providers as argued in the PJM/MISO proceedings. Old Dominion also contends that the Commission should add a requirement in the *pro forma* OATT that regional transmission costs be recovered through a single regional transmission rate of a rolled-in nature. Relative to cost recovery, Old Dominion believes that rolled-in zonal rates work for local facilities within a single transmission owner footprint, but regional rolled-in rates would be necessary for larger footprints.

606. Old Dominion also contends that the lack of periodic review by the Commission of stated transmission rates sends a strong economic signal to transmission owners to not invest in new transmission. Old Dominion argues that the Commission should require periodic rate reviews at least every five years or implement formula rates which would remove economic incentives for failing to build transmission.

607. EEI argues that the Commission should not address in this proceeding TDU Systems' proposal to require transmission providers to eliminate pancaked transmission rates in non-RTO regions because it involves complex issues that are not easily resolved. EEI contends that transmission providers should not be required to eliminate multiple transmission rates across multiple systems simply to allow TDU members to avoid the economic consequences of their decisions to

[357] *E.g.*, New Jersey Board, Ohio Power Siting Board, and WIRES.

[358] *E.g.*, APPA, NRECA, Old Dominion, and Seattle. APPA also suggests OASIS posting.

[359] *E.g.*, Arkansas Municipal, AWEA, FMPA, and TDU Systems.

[360] *E.g.*, Arkansas Municipal, TAPS, and TDU Systems.

purchase energy from off-system resources.

608. Other commenters ask the Commission to institute much broader market reforms in this rulemaking, arguing that the Commission will not be able to achieve its objectives of remedying undue discrimination and developing competitive wholesale markets without a fundamental change in market structures. Several commenters advocate changing the market structure in non-RTO markets to allow transmission customers to access the transmission provider's dispatch and redispatch options.[361] Some commenters[362] go further to assert that the Commission require the use of locational marginal pricing (LMP) as a part of OATT reform. Other commenters[363] assert that the Commission would not need to adopt a full RTO market design to achieve its more limited objectives, but contend that eliminating the fundamental inconsistency between the OATT rules and actual operation of the grid would remove a major obstacle to other reforms. Several commenters[364] contend that requiring use of a security constrained economic dispatch is a needed part of this reform.

609. Chandley-Hogan contend that the key element to ensuring transmission services are provided on a just, reasonable and not unduly discriminatory basis is to provide open access to the security constrained economic dispatch and the associated imbalance pricing that arises from that dispatch. Chandley-Hogan state that using a security constrained economic dispatch would also substantially reduce the problems inherent in the *pro forma* OATT's reliance on contract paths and ATC for transmission service scheduling.

610. Chandley-Hogan contend that a viable path to Order No. 888 reform is to start from the premise that open access to the dispatch (and redispatch) and marginal cost pricing for imbalances and redispatch to accommodate transmission are keys to getting open, non-discriminatory access to transmission. Chandley-Hogan argue that dispatch is the essential transmission service and providing open access to this dispatch is a path to achieving open, non-discriminatory access to transmission. Chandley-Hogan contend that a third party cannot effectively access the grid without accessing and closely interacting with the system operator's dispatch, including determining if transmission service is available, acquiring redispatch service to allow its schedule to proceed without curtailment, and settling imbalances from scheduled levels. Williams agrees with Chandley-Hogan that a system allowing non-RTO utilities to deny and curtail service requests whenever there is little ATC left and without offering redispatch to a third party is completely flawed. Williams argues that these same requests would be accommodated in an RTO through redispatch as long as the RTO has sufficient offers to arrange a security constrained economic dispatch.

611. EPSA argues on reply that an all-inclusive, ''asset-blind'' administration of open dispatch is needed to fully eliminate undue discrimination. EPSA states that security constrained dispatch will provide reliable operation and efficient utilization of the transmission grid by promoting the use of newer, cleaner and less expensive power plants. EPSA urges that these issues should be explored further here or in another policy proceeding. Project for Sustainable FERC Energy Policy asserts that there is no assurance of non-discriminatory access to transmission services and competitive wholesale markets unless load and potential competitors of the control area operators are treated comparably during dispatch. Project for Sustainable FERC Energy Policy supports additional provisions to the *pro forma* OATT requiring transparency and fairness in system dispatch and redispatch such as either an ''open dispatch'' requirement or a rule-based framework with standards of conduct and OASIS disclosure, as well as reporting and auditing requirement to eliminate anticompetitive incentives. Project for Sustainable FERC Energy Policy argues that sufficient data to establish marginal system costs and permit comparisons with the prices/costs of neighboring systems should be disclosed on OASIS.

612. PJM proposes open dispatch consisting of control of the dispatch function by a disinterested entity and the institution of a spot or balancing market to allow for the formation of real-time prices. Project for Sustainable FERC Energy Policy encourages the further separation of the system operator's dispatch functions from its merchant functions, to include specific dispatch transparency and comparability mandates as per PJM's and Transparent Dispatch Advocates' request. Project for Sustainable FERC Energy Policy supports comparable dispatch services through an independent entity. In its reply comments, Williams supports the rules based dispatch service proposed by PJM and states that it will reduce the opportunity for transmission providers to levy unjust and unreasonable redispatch rates.

613. PJM also contends that non-RTO/ISO systems have negative impacts on RTO systems because of the respective treatment of import transactions by non-RTOs/ISOs and RTOs/ISOs and the incidence of loop flows in market environments. PJM argues that entities scheduling flows through PJM that actually loop onto other systems nevertheless benefit financially because they collect the difference between the relatively high price at the interface where the energy is scheduled to enter the PJM footprint and the lower price at the interface where the energy is scheduled to leave the PJM footprint. When energy does not flow as scheduled, PJM states that the otherwise expected, beneficial impact on the transmission constraints are not realized, resulting in price differentials between the affected interfaces. As a result, PJM contends that such scheduled transactions only contribute to the FTR revenue adequacy issues PJM has experienced over the last 12 months.

614. PJM asserts that it is unduly preferential for a non-RTO/ISO utility to take advantage of the benefits of the organized markets of a bordering RTO/ISO without any obligation to bear any of the costs of administering those markets. PJM contends that it is unduly discriminatory and an impediment to the development of competitive markets to permit a non-RTO/ISO utility adjacent to an RTO/ISO's organized, transparent markets to accept the benefits of those markets and the regional transmission planning process that sustains them, while the same utility relies on non-market-based congestion management and limits the access of its competitors, including those who are members of the relevant RTO/ISO, to its dispatch sequence and wholesale prices within its service area. PJM asks the Commission to declare that it would not be unduly discriminatory for an RTO/ISO to include in its tariff a provision that makes an external system operator's access to those markets contingent on the external operator providing reciprocal access to its dispatch and planning functions for RTO/ISO members, as well as access to the external system's real-time marginal system cost information.

615. Transparent Dispatch Advocates propose on reply that the Commission require the industry to develop inter-

[361] *E.g.*, Chandley-Hogan, Constellation, and PJM.

[362] *E.g.*, Morgan Stanley and Steel Manufacturers Associations.

[363] *E.g.*, Chandley-Hogan and PJM.

[364] *E.g.*, EPSA and Chandley-Hogan.

control area coordination agreements to provide for reciprocal redispatch to alleviate constraints at specified border flowgates. Transparent Dispatch Advocates argue that redispatch over a larger area provides transmission providers more options to extract the full efficiency of their systems by allowing import/export transactions and intra-control area flows to continue that would otherwise be curtailed by providing redispatch of generation across a border at a lower cost than would result had the transaction been curtailed. Transparent Dispatch Advocates further propose that the Commission establish principles in the Final Rule to guide the development of these coordination agreements and require filing of the agreements within 12 months of the issuance of the Final Rule. Transparent Dispatch Advocates suggest that technical conferences may need to be scheduled to address any utility specific issues that arise.

616. Morgan Stanley and Steel Manufacturers Association contend that every control area should be moving toward LMP and that facing an imbalance cost measured by full replacement value of redispatch measured under LMP is the correct incentive to follow a schedule. Entegra similarly argues that customers and State regulators would benefit from more transparency regarding congestion on the transmission system and that the most efficient way to provide this transparency is to require transmission providers to apply LMP models to their systems and to post the resulting modeled LMPs.

617. Several commenters object to the proposal for a mandatory all-inclusive redispatch using bid-based pricing.[365] These commenters generally argue that such a proposal could not lawfully be adopted in the Final Rule because it dramatically departs from the scope of the NOPR. They also argue that the proposal is bad policy because there is no record showing that consumers would benefit from the costly and disruptive implementation required for the proposal and that adoption of the proposal would create controversy given that Congress and the Commission have already rejected an LMP-based model of industry restructuring. Sacramento adds that given the record of transmission investment in RTOs, open redispatch might not meet the transmission expansion goals of the NOPR.

618. Southern argues on reply that there is no legal basis for claims that a lack of open dispatch results in undue discrimination. Southern states that the entities at issue are not similarly situated and that open dispatch concerns resource procurement, an area beyond the scope of the Commission's jurisdiction. Southern further argues that the open dispatch remedy proposed by PJM and others would require radical restructuring and market reforms that are unfounded, lack a legal basis and would result in political discord. Southern states that open dispatch would violate FPA section 217 by threatening the ability of LSEs to maintain access to transmission rights to serve native load. In its reply comments, Entergy states that the open dispatch proposal should be rejected because it is unnecessary to ensure open access transmission service, is contrary to the Congressional intent in passing EPAct 2005, exceeds the scope of the Commission's jurisdiction by overriding State jurisdiction over sales to retail customers, and would result in opposition that will delay other reforms and distract the Commission with divisive litigation.

619. Sacramento states that the proposals for mandatory redispatch, the control of the dispatch by a disinterested entity, and the institution of a spot or balancing market to allow for the formation of real-time prices would undermine customers' objectives to receive uninterrupted transmission service at a predictable price and ignore transmission system operational limitations. Sacramento states that the value of mandatory redispatch in the Western Grid is limited because constraints often overlap and change from thermal to voltage to stability constraints at differing load levels and redispatching large amounts of generation to relieve constraints because of the distance between loads and generation cannot be achieved in the timeframes required to maintain reliability. Sacramento is concerned that PJM's proposal would cause appropriation of generation built to serve a transmission provider's native load in order to effectuate third-party transmission transactions, strain the transmission provider's grid, and cause additional curtailment of native load and firm transactions when a force majeure event occurs.

620. Entergy cites the approval of the ICT proposal as ample evidence that the incremental approach proposed in the NOPR is a better means of improving clarity, transparency and improvements in dispatch efficiency than the Transparent Dispatch Advocates and PJM seek to mandate. Entergy states that the arguments posed by PJM and Chandley-Hogan do not target remedying discrimination or ensuring comparability, but rather focus on what they believe are mechanisms for more efficient use of the grid. Overall, Entergy does not support any changes to the basic nature of the services available under the *pro forma* OATT or the development of real-time markets to ensure comparable access.

621. In its reply comments, Sacramento disagrees with PJM's claims that TLRs are a discriminatory substitute for real-time redispatch and PJM's proposal to eliminate such use of TLRs in favor of an expanded redispatch obligation. Sacramento argues that firm customers under the *pro forma* OATT do not expect TLRs, while those in Day 2 RTOs expect that generation will be redispatched. Sacramento adds that TLRs affect all loads, but that the nature of firm physical rights service is that it will not be interrupted except in very narrow defined circumstances.

622. Southern argues that customers selling between RTO and non-RTO systems are treated equally since part of the transaction is under an LMP treatment and the other part is under OATT treatment. In response to PJM's allegations that loop flows are unduly discriminatory to its customers, Southern states that loop flows are unavoidable consequences of integrating electrical systems and that PJM itself imposes loop flows on non-RTO systems, the effects of which are not compensated by PJM. If PJM believes that entities are free-riding on its system or manipulating its system, Southern argues that PJM could seek to increase market participation charges or file a complaint with the Commission. Sacramento agrees that this rulemaking is the wrong forum for resolving seams issues given the stated scope of the NOPR. Sacramento adds that border utilities do not ''free ride'' on RTO markets because these markets impose significant costs on border entities. Sacramento also disagrees that open redispatch would resolve loop flow problems and suggests other mechanism for addressing loop flow. Finally, Sacramento states that TLRs are an Eastern Interconnection process that, although rare, occur in RTOs and non-RTO areas.

Commission Determination

623. As the Commission explained in the NOPR, we do not intend to undertake a comprehensive overhaul of our transmission pricing policies in this rulemaking. Instead, the Commission proposed a number of specific reforms to discrete provisions in the *pro forma* OATT and a clarification to our ''higher of'' policy for pricing of transmission system expansions. Given the limited

[365] *E.g.,* LPPC, Entergy, and Sacramento.

scope of this proceeding, we do not believe it would be appropriate to adopt the broader ratemaking proposals suggested by commenters. Issues of rate pancaking, including joint rates, regional rolled-in rates and rate reviews are beyond the scope of this proceeding.

624. Similarly, the Commission made clear in the NOPR that the purpose of the proposed rule is to strengthen the *pro forma* OATT to remedy undue discrimination and not to impose any particular market structure on the industry. The Commission's focus in this proceeding was and remains the development of competitive wholesale markets through the reduction of barriers to entry created through the control of transmission assets. We continue to believe that the appropriate focus of this rulemaking is to strengthen competitive wholesale markets by adopting reforms to address remaining areas of undue discrimination and issues of comparability rather than mandating a fundamental change in the market structure.

625. We therefore reject requests to institute systems that require the real-time use of regional security constrained economic dispatch and LMP for granting real-time transmission service and for the settlement of imbalances or to otherwise require transmission providers to use LMP-based modeling. We believe that LMP market designs can provide significant benefits to customers through more efficient use of the grid, but do not believe that such market designs are the only way to remedy undue discrimination or achieve comparability. We continue to support regional flexibility in market development, provided that the market design implemented by the transmission providers provides other transmission customers with comparable service to that which the transmission providers provide to their own native loads and affiliates.

626. We also reject arguments regarding seams issues creating an undue discrimination between market and non-market areas that must be resolved in this proceeding. We note that there are currently processes underway to address seams issues both in the Eastern and Western Interconnections.[366] We believe that such seams issues are beyond the scope of this rule and are better addressed on a case-by-case basis or, as appropriate, in the proceeding on RTO Border Utility Issues.[367]

2. Energy and Generation Imbalances

627. In Order No. 888, the Commission concluded that six ancillary services must be included in an OATT.[368] One of those ancillary services is energy imbalance service under Schedule 4 of the pro forma OATT.[369] Energy imbalance service is provided when the transmission provider makes up for any difference that occurs over a single hour between the scheduled and the actual delivery of energy to a load located within its control area.[370] The Commission recognized, in general, that the amount of energy taken by load in an hour is variable and not subject to the control of either a wholesale seller or a wholesale requirements buyer.[371]

628. The Commission found that energy imbalance service should have an energy deviation band appropriate for load variations and a price for exceeding the deviation band that is appropriate for excessive load variations.[372] The Commission established an hourly deviation band of +/−1.5 percent (with a minimum of 2 MW) for energy imbalance. The Commission explained that this deviation band promotes good scheduling practices by transmission customers, which ensures that the implementation of one scheduled transaction does not overly burden another.[373]

629. With respect to compensation associated with the hourly energy deviation band, the Commission explained that, for energy imbalances within the deviation band, the transmission customer may make up the difference within 30 days (or other reasonable period generally accepted in the region) by adjusting its energy deliveries to eliminate the imbalance (*i.e.*, return energy in kind within 30 days).[374] In addition, the Commission explained that the transmission customer must compensate the transmission provider for each imbalance that exceeds the hourly deviation band and for accumulated minor imbalances that are not made-up within 30 days.[375] With respect to the price of energy imbalance service, the Commission explained that it intentionally did not provide detailed pricing requirements.[376] Instead, the Commission required transmission providers to propose rates for energy imbalance service.[377]

630. Although transmission providers have different energy imbalance charges, they typically require customers to correct energy imbalances within the deviation band through return in kind or a financial settlement that requires payment for underdeliveries of energy equal to 100 percent of the transmission provider's system incremental cost for the hour the deviation occurred. For energy overdeliveries, the transmission customer would receive a payment equal to 100 percent of the transmission provider's decremental cost for the hour the deviation occurred.[378] Outside the deviation band, transmission providers either charge the transmission customer (1) A percentage of the utility's system cost, such as 110 percent of incremental costs for underscheduling or 90 percent of decremental costs for overscheduling or (2) the greater of a percentage of system costs or a fixed charge, such as $100 per MWh.[379]

631. While the Commission found in Order No. 888 that energy imbalance was an ancillary service, it also recognized that another imbalance may arise for differences between energy scheduled for delivery from a generator and the amount of energy actually generated in an hour,[380] commonly called generator imbalance. The Commission concluded, however, that a generator should be able to deliver its scheduled hourly energy with precision and expressed concern that allowing a generator to deviate from its schedule by 1.5 percent without penalty, so long as

[366] See, *e.g.*, *RTO Border Utility Issues*, Notice of Technical Conference on Seams Issues for RTOs and ISOs in the Eastern Interconnections, (Docket No. AD06–9–000) (issued Jan. 25, 2007).

[367] *Id.*

[368] Order No. 888 at 31,703.

[369] *Id.*

[370] *See Id.* at 31,960.

[371] Order No. 888–A at 30,230.

[372] *Id.*

[373] *Id.* at 30,232.

[374] *Id.* at 30,229.

[375] *Id.* The Commission further stated that the *pro forma* OATT permits schedule changes up to twenty minutes before the hour at no charge, and that it would allow the transmission provider and the customer to negotiate and file another deviation band more flexible to the customer, if the same deviation band is made available on a not unduly discriminatory basis. *Id.* at 30,232–33.

[376] *Id.* at 30,234

[377] *Id.*

[378] *See, e.g.,* Arizona Public Service Co., FERC Electric Tariff, Twelfth Revised Volume No. 2, Schedule 4 (Energy Imbalance Charge), accepted in *Arizona Public Service Co.,* Docket No. ER04–442–003 (Sep. 30, 2004) (unpublished letter order); Public Service Company of New Mexico, FERC Electric Tariff, Second Revised Volume No. 4., Schedule 4 (Energy Imbalance Charge), accepted in *Public Service Co. of New Mexico,* Docket No. ER04–416–002 (Sep. 30, 2004) (unpublished letter order).

[379] *See Idaho Power Co.,* 102 FERC ¶ 61,351 (2003); Duke Electric Transmission FERC Electric Tariff, Third Revised Volume 4, Original Sheet No. 120 accepted in *Duke Energy Corp.,* Docket No. ER04–812–001 (Jul. 2, 2004) (unpublished letter order).

[380] Order No. 888–A at 30,230.

it returned the energy in kind at another time, would discourage good generator operating practices.[381] The Commission stated that a generator's interconnection agreement with its transmission provider or control area operator should specify the requirements for the generator to meet its schedule and any consequence for persistent failure to meet its schedule.[382]

632. The Commission subsequently accepted in a number of cases modifications to a transmission provider's OATT to include generator imbalance provisions.[383] Moreover, in Order No. 2003–B, the Commission permitted the transmission provider to include a provision for generator balancing service arrangements in individual interconnection agreements.[384] Further, in a NOPR concerning generator imbalance provisions for intermittent resources, the Commission proposed to establish a standardized schedule under the *pro forma* OATT to address generator imbalances created by intermittent resources and to clarify the application of the current energy imbalance provision of the *pro forma* OATT.[385] In particular, the Commission proposed that generator imbalance provisions for intermittent resources would reflect a deviation band of +/−10 percent (with a minimum of 2 MW) and allow net hourly intermittent generator imbalances within the deviation band to be settled at the system incremental cost at the time of the imbalance.[386] The Commission also reiterated its policy that a transmission provider may only charge the transmission customer for either hourly generator imbalances or hourly energy imbalances for the same imbalance, but not both.[387]

633. A variety of different deviation bands and pricing methods are on file for generator imbalances. Rates for generator imbalance underdeliveries range from the greater of $100/MWh or 110 percent of system incremental cost to the greater of $150/MWh or 200 percent of the incremental cost.[388] Generator imbalance rates for overdeliveries range from 90 percent [389] of system decremental cost to 50 percent [390] of the decremental cost.

a. Tiered Approach to Imbalance Penalties in the OATT

NOPR Proposal

634. In the NOPR, the Commission noted that the existing energy imbalance charges described in Order No. 2003 are the subject of significant concern and confusion in the industry. The Commission expressed concern about the variety of different methodologies used for determining imbalance charges and whether the level of the charges provides the proper incentive to keep schedules accurate without being excessive. The Commission therefore proposed to modify the current *pro forma* OATT Schedule 4 treatment of energy imbalances and to adopt a separate *pro forma* OATT schedule for the treatment of generator imbalances.

635. The Commission proposed to create new energy and generator imbalance schedules based on the following three principles: (1) The charges must be based on incremental cost or some multiple thereof; (2) the charges must provide an incentive for accurate scheduling, such as by increasing the percentage of the adder above (and below) incremental cost as the deviations become larger; and (3) the provisions must account for the special circumstances presented by intermittent generators and their limited ability to precisely forecast or control generation levels, such as waiving the more punitive adders associated with higher deviations.

636. The Commission noted that Bonneville has adopted an energy imbalance pricing approach based on a three-tiered deviation band that appears workable for both energy imbalance service and generation imbalance service. Under this approach, imbalances of less than or equal to 1.5 percent of the scheduled energy (or two megawatts, whichever is larger) would be netted on a monthly basis and settled financially at 100 percent of incremental or decremental cost at the end of each month. Imbalances between 1.5 and 7.5 percent of the scheduled amounts (or two to ten megawatts, whichever is larger) would be settled financially at 90 percent of the transmission provider's system decremental cost for overscheduling imbalances that require the transmission provider to decrease generation or 110 percent of the incremental cost for underscheduling imbalances that require increased generation in the control area. Imbalances greater than 7.5 percent of the scheduled amounts (or 10 megawatts, whichever is larger) would be settled at 75 percent of the system decremental cost for overscheduling imbalances or 125 percent of the incremental cost for underscheduling imbalances. Intermittent resources are exempt from the third-tier deviation band and pay the second-tier deviation band charges for all deviations greater than the larger of 1.5 percent or two megawatts.

637. The Commission sought comment regarding whether this tiered approach should be adopted for inclusion in the *pro forma* OATT for energy and generator imbalances. The Commission specifically asked whether this approach provides sufficient incentives to ensure that transmission systems can be operated in a reliable manner and ensure that customers are treated in a just and reasonable manner.

Comments

638. A number of entities generally support a tiered approach to imbalance penalties that progressively increases the penalties for imbalances, as implemented by Bonneville.[391] These

[381] *Id.*

[382] *Id.*

[383] *See, e.g., Niagara Mohawk Power Corp.,* 86 FERC ¶ 61,009, *order on reh'g,* 87 FERC ¶ 61,148 (1999) (*Niagara Mohawk*); *PacifiCorp,* 95 FERC ¶ 61,145, *order on reh'g and clarification,* 95 FERC ¶ 61,467 (2001); *Alliant Energy Corporate Services, Inc.,* 93 FERC ¶ 61,340 (2000); *Wolverine Power Supply Coop.,* 93 FERC ¶ 61,330 (2000); *Commonwealth Edison Co.,* 93 FERC ¶ 61,021 (2000); *FirstEnergy Operating Cos.,* 93 FERC ¶ 61,200 (2000), *order denying reh'g & granting clarification,* 94 FERC ¶ 61,184 (2001); *Tampa Electric Co.,* 90 FERC ¶ 61,330 (2000), *reh'g denied,* 95 FERC ¶ 61,101 (2001); *Florida Power Corp.,* 89 FERC ¶ 61,263 (1999); *Consumers Energy Co.,* 87 FERC ¶ 61,170 (1999) (*Consumers*).

[384] Order No. 2003–B at P 74–75.

[385] *Imbalance Provisions for Intermittent Resources; Assessing the State of Wind Energy in Wholesale Electricity Markets,* Notice of Proposed Rulemaking, 70 FR 21349 (Apr. 26, 2005), FERC Stats. & Regs. ¶ 32,581 at P 9 (2005) (Imbalance Provisions Proceeding).

[386] The Commission defined incremental cost as ''the transmission provider's actual average hourly cost of the last 10 MW dispatched to supply the transmission provider's native load, based on the replacement cost of fuel, unit heat rates, start-up costs, incremental operation and maintenance costs, and purchased and interchange power costs and taxes.'' *Id.* at P 9 n.17 (*citing Consumers,* 87 FERC ¶ 61,170 at 61,179 (1999)).

[387] Under existing Commission policy, a transmission provider may only charge a transmission customer for the penalty percent adder to the incremental cost for either hourly generator imbalances or hourly energy imbalances for the same imbalance. For example, if a transmission customer has a 100 MWh point-to-point schedule in a control area, but produces 105 MWh and consumes 105 MWh, the transmission provider may charge the transmission customer 110% of its incremental cost for the 5 MWh of energy imbalance, but then must pay the transmission customer its incremental cost for the 5 MWh generator imbalance.

[388] *See Duke Energy Corp.,* Docket No. ER05–855–000 (Dec. 20, 2005) (unpublished letter order) (accepting Duke Electric Transmission's Large Generator Interconnection Agreement with Power Ventures Group, LLC (Duke Delegated Letter Order)).

[389] *See Entergy Services, Inc.,* 90 FERC ¶ 61,272 (2000) (concerning various generator imbalance agreements).

[390] *See* Duke Delegated Letter Order.

[391] *E.g.,* Ameren, Northwest IOUs, Progress Energy, Suez Energy NA, Public Power Council, Sacramento, South Carolina E&G, Pinnacle, Allegheny, TDU Systems, Constellation, Imperial, and Morgan Stanley.

commenters generally state that a graduated bandwidth approach recognizes the link between escalating deviations and potential reliability impacts on the system. Other entities, however, take issue with aspects of the Commission's proposal or propose a different approach to resolving imbalances. For example, Entegra submits that the Commission should require transmission providers to establish, or permit market participants to establish, markets or pools for the netting and settlement of imbalances. Steel Manufacturers Association argues for the Commission to require real-time balancing markets.

639. Among those supporting the Commission's proposal, Ameren asserts that the tiered approach properly allows for higher penalties for imbalances that have a greater impact on the system and thus have a greater potential to affect reliability. NorthWestern is not opposed to the generation imbalance provisions applying to all generators, arguing that imbalance charges must be based upon incremental cost and must provide an incentive for accurate scheduling. Morgan Stanley contends that basing the imbalance charge on incremental cost should be a bedrock principle for developing methods to financially settle imbalances.

640. Progress Energy, Sacramento, and Entergy encourage the Commission to allow each transmission provider to have the flexibility to craft penalty provisions that provide the right incentives to encourage their transmission customers to act responsibly. Grant similarly contends that the transmission provider must be able to decide what to charge for imbalance services and must consider the incentives for resource development and the potential for cross-subsidies paid by other customers associated with such pricing. Grant argues that transmission providers should have an ability to ''opt out'' if they can demonstrate an inability to provide the service without creating an undue burden on other ratepayers.

641. Constellation, while supporting the Commission's proposal, asks that transmission providers be required to utilize a security-constrained economic dispatch to procure and settle imbalances at least cost, which would ensure that least cost is determined on the most efficient basis. Constellation contends that imbalance charges should be based on the transmission provider's actual cost of meeting a positive imbalance or liquidating a negative imbalance, which costs can include required ancillary services and redispatch costs. Morgan Stanley states that facing an imbalance cost measured by full replacement value of redispatch measured under LMP would be an appropriate incentive. Morgan Stanley contends that the *pro forma* OATT should specify using opportunity cost principles to charge for imbalance solutions in those areas without LMP and come as close to mimicking the result under LMP as possible. In reply comments, Mark Lively suggests the Commission make the price for imbalances a function of the size of Area Control Error. Public Power Council recommends that transmission providers not assess penalties against loads or resources when their deviations from the schedule help the system in a given delivery hour. TDU Systems argue that inadvertent scheduling errors that do not threaten system integrity or reliability should not be penalized through charges for imbalances that exceed incremental cost in the upper tiers of imbalance bandwidths.

642. Although FirstEnergy states that the Bonneville approach for generator imbalances is appropriate, it argues that the current *pro forma* OATT methodology for calculating and assessing energy imbalances should be retained. FirstEnergy argues that it is more appropriate and fair to apply a graduated penalty structure to generation imbalances since greater deviations usually occur from generation. Ameren, however, believes that generators are generally better able to control their imbalances than transmission customers who take energy off of the system and that the use of a narrower deviation band may be appropriate for generator imbalances. Nonetheless, Ameren states that it does not oppose the Commission's proposal to use the same deviation bandwidths for both energy imbalances and generator imbalances.

643. Ameren contends that developing standardized provisions for generator imbalances in the OATT would eliminate the plethora of penalties that now exist. Ameren asserts that moving to a tariff approach would increase transparency and would help address the situation where such provisions may appear either in the relevant OATT or in specific interconnection agreements (at least for interconnection agreements entered into as of the date of the revised tariff provisions). Progress Energy and South Carolina E&G support separate tariff (or Generator Interconnection Agreement) provisions for these services, suggesting that generator and energy imbalance provisions could be tailored for generators and LSEs. NorthWestern states that it has long been an advocate of the inclusion of a generation imbalance OATT mechanism. TDU Systems contend that the Commission should require that the specific bandwidths and the basis for the charges be spelled out in detail in the revisions to the *pro forma* OATT and in each transmission provider's tariff. Allegheny argues that changing Energy Imbalance Service from Schedule 4 to Schedule 4a, adding a new Schedule 4b for Generator Imbalance Service, and eliminating proposed Schedule 9 would call attention to the fact that a transmission provider may only charge a transmission customer either an hourly generator imbalance charge or an hourly energy imbalance charge, but not both for the same imbalance.

644. Other entities contend that the Commission's imbalance proposal will not do enough to protect reliability and prevent entities from deviating from their schedules. Entergy states that the Commission should recognize that a system with significant hydro resources, such as the Bonneville system, faces different challenges in matching generation and load than a system with predominantly thermal generation. Unlike the fast ramping capability of hydro units, Entergy asserts that thermal units have a more limited ability to adjust and compensate for imbalances. Entergy adds that the Bonneville model may not provide sufficient incentives in those areas with large amounts of independent generation. In reply comments, some APPA members noted that wind variability may pose significant operational concerns that could increase regulating reserve requirements, particularly on smaller transmission systems.

645. Steel Manufacturers Association asks the Commission to delete any further reference to charges based on some multiple of incremental costs, which applies to scheduling incentives, not cost recovery. It believes that charges based on multiples of incremental costs are not necessary and do not produce rates that are just and reasonable. Steel Manufacturers Association asserts that balancing mechanisms based on real time market-clearing prices provide full compensation and adequate scheduling incentives in the organized markets and there is no reason to apply a deadband/penalty mechanism for individual OATT providers unless there is a demonstrated need, *i.e.*, a showing that excessive gaming by LSEs or generators has been a problem.

646. Steel Manufacturers Association also contends that the current imbalance mechanism is a losing proposition for loads that cannot control energy

consumption to match an hourly schedule of energy deliveries, with transmission providers receiving windfall revenues. It argues that the mechanism is unfair to smaller transmission systems that are not control areas (and therefore may not settle all of their imbalances through return-in-kind energy) and certain retail customers that take unbundled retail transmission service. Steel Manufacturers Association asks the Commission to institute a larger bandwidth of, at minimum, 10 percent for small wholesale customers and discrete retail loads. It contends that large utilities and wholesale transmission customers that acquire power for many discretely operated loads with varying load stages and load factors and averaging those loads creates an overall predictability to load curves that permits the practical use of a 1.5 percent bandwidth for large utilities and wholesale customers.

647. Utah Municipals assert that the Commission is wrong to believe that imbalances tend to result from carelessness or intentional conduct rather than unavoidable uncertainties and error. Utah Municipals contend that, while technology that permits perfectly accurate scheduling (*i.e.*, namely the AGC equipment used by control area operators) is theoretically available, it is prohibitively expensive for many transmission customers and unavailable to those who do not own generation. Utah Municipals argue that financial incentives for accurate scheduling do not alter scheduling behavior or actual imbalances, but only result in a potential windfall for the transmission provider and a potentially significant competitive advantage for the transmission provider's market function, which (because of the AGC equipment that all transmission customers pay for through rates) will not be subject to the charges. Utah Municipals suggest that the Commission limit the imbalance charges for unintentional deviations by applying the third deviation band only to intentional imbalances.

648. Imperial argues that the Bonneville approach would not provide appropriate incentives for small geothermal generating units on its system to control their scheduled output, especially if imbalances are recorded on an hourly basis rather than on a cumulative basis over the course of a month. Under the Bonneville approach, Imperial asserts that it would have to pay its generators 100 percent of its incremental cost for overgeneration because such imbalances are usually less than 2 MW in any given hour. It states that using a 100 percent credit for net overgeneration would result in crediting the generator more than $28,500.

649. WECC states that it is very important to differentiate between the kind of behavior that the Commission is worried about and appropriate practices that support system reliability. WECC is concerned that inflexible generator imbalance provisions in the *pro forma* OATT may create incentives for generators in the West to restrict governor action on their generators in ways that degrade system reliability. WECC notes that the number of rotating machines connected to the grid in the Eastern Interconnection is much greater than in the Western Interconnection, which impacts the ability of generators to respond to maintain frequency when a system's load-resource balance changes. WECC explains that a sudden change in load-resource balance of a particular magnitude (for example, the loss of a 1,000 MW generating plant) will require a proportionately greater response from each generating unit in the West as compared to the Eastern Interconnection. WECC contends that in the West a significant frequency decline could cause responding generators to exceed a 1.5 percent deviation threshold applied under current *pro forma* Tariff imbalance schedules.

650. If the manner of implementing generator imbalance charges in the West does not consider the need for generators to respond to frequency deviations, WECC worries that these charges could produce perverse incentives that will undermine reliability. WECC argues that generators that use set-point controllers to override governor action will be less likely to incur imbalance charges and penalties, while those with properly operating governors may be punished for deviating from scheduled output to respond to system reliability needs. WECC believes that this has in fact been happening in the West and is one of the reasons that frequency response in the Western Interconnection has deteriorated in recent years. WECC urges the Commission to consider how generators can be given appropriate incentives to meet their obligations to supply energy to load but also to support system reliability by effectively responding to frequency deviations. WECC explains that the Commission could adopt a policy that set-point controllers should not be allowed to override governor response. WECC suggests that deviations from scheduled generator output needed to correct frequency decay could be excused from imbalance penalties under the *pro forma* OATT.

651. Indianapolis Power contends on reply that variation should be allowed to account for the individual facts and circumstances associated with a specific region as well as specific types of intermittent resources. A number of entities agree with providing flexibility to intermittent generators, but suggest different ways of doing so.[392] Fertilizer Institute agrees that intermittent resources should be exempt from any penalties beyond the 90 percent/110 percent ''second tier.'' However, Fertilizer Institute also believes that intermittent resources should receive greater tolerance before they run into the 90 percent/110 percent penalty level in the first place. Fertilizer Institute urges the Commission to relax the first-tier tolerance band from 2MW to 20MW (or 40 percent of nameplate capacity, whichever is greater) for intermittent generators only. It asserts that this action is consistent with the Commission's recognition that intermittent generators can undergo sudden changes of conditions for which they cannot fairly be held responsible. Fertilizer Institute argues that a broader first-tier tolerance band for these generators will present no threat to the transmission grid, because intermittent generation facilities are limited both in size and in number.

652. Geothermal Producers supports a first-tier deviation band of +/−5 percent for intermittent resources, rather than the 1.5 percent threshold proposed by Bonneville. Geothermal Producers believes a 5 percent band is appropriate for intermittent resources, since a five percent band more accurately recognizes that intermittent resources are less capable of controlling deviations from schedules than are conventional resources. For over- or under-deliveries in excess of five percent, Geothermal Producers contends that intermittent resources should be charged no more than the control area's cost of supplying energy to correct the imbalance. Geothermal Producers also supports Bonneville's position that intermittent resources should be exempt from the third-tier deviation band and instead should pay the second-tier deviation band charges for all deviations greater than the second-tier deviation band.

653. Other commenters, however, do not support providing exceptions for

[392] *E.g.*, NorthWestern, Fertilizer Institute, and Geothermal Producers.

intermittent resources.[393] If society decides to provide incentives for intermittent resources, Morgan Stanley states that this is better done in a direct fashion, such as a certification program akin to resource adequacy rules that require LSEs to source a proportion of supply from such resources. Morgan Stanley asserts that this would motivate developers to mitigate imbalance costs through other market or technical means to the full extent of the economic signal imbedded in the imbalance price and thereby optimize the design and operation of such resources. MidAmerican argues on reply that special treatment of intermittent resources and loads has the effect of penalizing those resources and loads that have made investments to manage scheduling and enhance reliability. TDU Systems believe that the NOPR's third principle, which requires transmission providers to accord special treatment to intermittent generators, is contrary to the principle of comparability.

654. Northwest IOUs argue that the transmission provider should have the option to elect whether to exempt intermittent resources from the third-tier deviation band and instead charge, in a not unduly discriminatory or preferential manner, the second-tier deviation band charge for all deviations greater than the larger of 1.5 percent or 2 megawatts.

655. Several commenters suggested that the Commission include a definition of intermittent resource in the final rule. Fertilizer Institute and South Carolina E&G contend that it is essential for the Commission to provide a clear definition of ''intermittent generation'' or ''intermittent resource'' to avoid disputes. Fertilizer Institute argues that the question of whether a given generator is ''intermittent''—and thereby entitled to the special provisions—is likely to become a source of contention. Fertilizer Institute suggests that an intermittent resource be defined as ''an electric generator that (1) Cannot store its fuel sources and (2) has limited capability to be dispatched and to respond to changes in system demand and transmission security constraints.'' EEI, however, suggests that the definition apply only to weather-driven units. Fertilizer Institute argues on reply that restricting the definition in this way would be unduly discriminatory. Fertilizer Institute argues that the definition should include the most common forms of intermittent generation—wind and solar power—as well as the less common but equally valuable forms, such as generation with ocean energy or ''waste heat'' from an industrial process. Fertilizer Institute asserts that the Commission should not broaden the definition of intermittent resource to encompass generators who are not truly ''intermittent'' and should not narrow the definition to exclude some intermittent generators in favor of others. Fertilizer Institute contends on reply that a generator should not have to be ''weather-driven'' to qualify as ''intermittent.'' Geothermal Producers supports the inclusion of geothermal energy as an intermittent resource. Geothermal Resources contends that geothermal resources satisfy both the Commission's proposed definition and the EEI proposal.

656. Ameren and Entergy ask the Commission to clarify that it does not intend to amend any existing interconnection agreements to require the use of any *pro forma* imbalance penalties. Entergy believes that the present form of its Generation Interconnection Agreement is absolutely critical to managing imbalances on its system and maintaining reliability. Entergy states that it has developed specialized software to monitor and manage generator imbalances and employs six system operators (one per shift) to monitor and manage generator imbalances.

657. Although Entergy supports the ''grandfathering'' of existing generator imbalance arrangements, it does not believe that it would be appropriate to require the prospective use of a different methodology while simultaneously maintaining the grandfathered arrangements. Entergy contends that administering two different generator imbalance arrangements would not be consistent with the comparability principles of Order No. 888 and would be difficult and costly from an operational perspective.

658. Several commenters [394] argue on reply that it would be inappropriate for the Commission to grandfather existing imbalance provisions. In its reply comments, Entegra argues that prior arrangements should remain in place only if a transmission provider can demonstrate that its existing imbalance arrangements are consistent with or superior to the provisions of the *pro forma* OATT as modified by the Final Rule in this proceeding.

659. EEI and Exelon contend that the transmission provider may not be able to charge a generator under its OATT if the generator is not the transmission customer and, therefore, generators should be able to include standardized imbalance terms in agreements with eligible customers prior to providing service. Exelon suggests that the Commission both adopt in the *pro forma* OATT a standard imbalance penalty structure and direct transmission providers to include the same terms and conditions in their interconnection agreements with generators. TAPS suggests on reply that each generator could simply be required to sign a service agreement that requires it to comply with the generator imbalance provisions of the transmission provider's OATT. Unless the *pro forma* OATT governs both generator and load imbalances, TAPS argues that it would be impossible to implement and enforce the Commission's prohibition against charging both energy and generator imbalances for a single transaction.

660. ICNU argues on reply that the Commission should adopt less restrictive imbalance charges for retail access customers or, at a minimum, continue to recognize that the standard energy imbalance charge needs to be modified to accommodate direct access customers. ICNU asks the Commission to modify its proposed imbalance provision to reflect the unique characteristics of direct access customers by adopting wider imbalance bandwidths and/or waiving the more punitive adders associated with higher deviations.

661. Several entities assert that the proposed imbalance reform should not apply to RTOs. Exelon requests that the Commission explicitly state that these rules do not apply in regions that have organized markets, such as PJM, that obviate the need for imbalance penalties. They contend that within organized markets, an imbalance penalty rule is not necessary, as the independent transmission operators have effectively addressed the concerns that the proposed imbalance schedules are intended to address. Indicated New York Transmission Owners contend that the Commission should grant the NYISO a regional variation from the revised *pro forma* OATT with respect to imbalance charges. It contends that the existing mechanisms in ISO/RTO markets with LMP are consistent with the Commission's objectives in its NOPR and that the Commission should permit a regional variation to the NYISO. SPP states that the Commission should state that it does not intend to affect its effort to implement a real-time energy imbalance market by any final rule. SPP further contends that the Commission should clarify that its energy imbalance changes do not apply to ISOs and RTOs with organized

[393] *E.g.*, Morgan Stanley, Northwest IOUs, Steel Manufacturers Association, and TDU Systems.

[394] *E.g.*, Fertilizer Institute, Entegra, and TAPS.

markets providing for real-time energy imbalance markets. SPP believes that the Commission should view the existence of a spot energy price in organized markets as superior to penalties based on incremental costs or some multiple thereof.

662. Entegra suggests that, since many RTOs have (or are developing) separate markets for commitment costs, it may not be necessary to incorporate such costs into imbalance prices in certain RTO markets. Organizations of MISO and PJM States contend that this proposed change to Schedule 4 is not applicable in the RTO context and argue that, to the extent that the Commission's suggestions regarding the special circumstances presented by intermittent generators are applicable to RTOs, those issues are best addressed in a context other than the instant rulemaking proceeding.

Commission Determination

663. In order to increase consistency among transmission providers in the application of imbalance charges, and to ensure that the level of the charges provides appropriate incentives to keep schedules accurate without being excessive, the Commission adopts in the *pro forma* OATT imbalance provisions similar to those implemented by Bonneville. We agree with commenters that a graduated bandwidth approach recognizes the link between escalating deviations and potential reliability impacts on the system. Furthermore, we conclude that these provisions adhere to the three principles discussed in the NOPR, which we also adopt here: (1) The charges must be based on incremental cost or some multiple thereof; (2) the charges must provide an incentive for accurate scheduling, such as by increasing the percentage of the adder above (and below) incremental cost as the deviations become larger; and (3) the provisions must account for the special circumstances presented by intermittent generators and their limited ability to precisely forecast or control generation levels, such as waiving the more punitive adders associated with higher deviations.

664. Specifically, imbalances of less than or equal to 1.5 percent of the scheduled energy (or two megawatts, whichever is larger) will be netted on a monthly basis and settled financially at 100 percent of incremental or decremental cost at the end of each month. Imbalances between 1.5 and 7.5 percent of the scheduled amounts (or two to ten megawatts, whichever is larger) will be settled financially at 90 percent of the transmission provider's system decremental cost for overscheduling imbalances that require the transmission provider to decrease generation or 110 percent of the incremental cost for underscheduling imbalances that require increased generation in the control area. Imbalances greater than 7.5 percent of the scheduled amounts (or 10 megawatts, whichever is larger) will be settled at 75 percent of the system decremental cost for overscheduling imbalances or 125 percent of the incremental cost for underscheduling imbalances.

665. The Commission adopts Bonneville's tariff provisions that provide that intermittent resources are exempt from the third-tier deviation band and would pay the second-tier deviation band charges for all deviations greater than the larger of 1.5 percent or two megawatts. We believe this is consistent with the fact that intermittent generators cannot always accurately follow their schedules and that high penalties will not lessen the incentive to deviate from their schedules.

666. Several commenters argue that the Commission should adopt a standard definition of intermittent resource. In order to clarify application of imbalance charges, we define an intermittent resource for this limited purpose as ''an electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints.''[395] We conclude that this definition of intermittent resource properly limits the exemption from imbalance charges, without excluding certain classes of intermittent generators for which the exemption is appropriate (*e.g.*, non-weather driven intermittent resources).

667. The Commission believes that adopting a tiered approach for both energy and generation imbalances will best balance the needs of transmission providers to operate their transmission systems in a reliable manner with the needs of transmission customers to have reasonable access to those systems at just and reasonable rates. Furthermore, we conclude that the partial exemption from imbalance charges for intermittent resources appropriately reflects the special circumstances faced by such resources and, consequently, is not unduly discriminatory. Moreover, formalizing generator imbalance provisions in the *pro forma* OATT will standardize the future treatment of such imbalances from the wide variety of generator imbalance provisions that exist today in various generator interconnection agreements. Standardizing generator imbalances should lessen the potential for undue discrimination, increase transparency and reduce confusion in the industry that results from the current plethora of different approaches.

668. Several commenters debate whether the imbalance provisions adopted here should be applied to energy imbalances, generation imbalances, or both. The Commission concludes that subjecting both energy and generation imbalances to the same charges is appropriate. Energy and generation imbalances have the same net effects on the transmission system in requiring other generation to be ramped up or down to make up for the imbalance. As such, the Commission will modify the current *pro forma* OATT Schedule 4 treatment of energy imbalances and adopt a new separate *pro forma* OATT Schedule 9 for the treatment of generator imbalances, each based on the tiered structure described above. To the extent a transmission provider wishes to deviate from these revised *pro forma* provisions, it may demonstrate in an FPA section 205 proceeding that the proposed changes are consistent with or superior to the *pro forma* OATT as modified by this Final Rule. However, we note that proposed alternative provisions must comply with the three imbalance charge principles addressed in the NOPR and adopted in this Final Rule and be consistent with or superior to the specific imbalance charges set forth in the *pro forma* OATT (and discussed above).

669. Some commenters stated that the Commission should require transmission providers to establish, or permit market participants to establish, markets or pools for the netting and settlement of imbalances. As explained previously, the purpose of this rule is to strengthen the *pro forma* OATT to remedy undue discrimination and not to impose any particular market structure. If transmission providers offer to modify their OATTs to allow such pools, we will consider such proposals. But, imposing such requirements goes beyond the scope of this proceeding. The Commission therefore declines, for all these reasons, to impose the structural reforms requested by some commenters.

670. The Commission instead adopts the three-tiered approach in the *pro*

[395] *See* Docket No. RM05–10–000. We note that this definition was proposed by the Commission in the NOPR on Imbalance Provisions for Intermittent Resources. *See Imbalance Provisions for Intermittent Resources; Assessing the State of Wind Energy in Wholesale Electricity Markets,* Notice of Proposed Rulemaking, 70 FR 21349 (Apr. 26, 2005), FERC Stats. & Regs. ¶ 32,581 (2005).

forma OATT. As with other reforms adopted in this Final Rule, all transmission providers must submit compliance filings containing these *pro forma* tariff provisions. Transmission providers with previously-approved tariff provisions governing imbalances that no longer conform to the *pro forma* OATT, as revised in this Final Rule, may seek renewed approval of those tariff deviations in accordance with the procedures described in section IV.C above, demonstrating that the alternative imbalance charge structures are consistent with or superior to the reformed *pro forma* OATT. With respect to the concerns raised by ISOs and RTOs, we agree that LMP-based markets can provide an efficient and nondiscriminatory means of settling imbalances and, as indicated in the NOPR, we are not proposing to redesign ISO/RTO markets in this rulemaking. Nevertheless, ISOs and RTOs must follow the procedures described in the Applicability section for seeking approval of deviations that are consistent with or superior to the *pro forma* OATT.

671. We do not, however, abrogate existing generator imbalance agreements between transmission providers and their customers. These agreements have been negotiated between willing parties, and the Commission will not re-open them generically in this proceeding. To the extent a particular party desires to amend an existing generator imbalance agreement in light of the reforms we adopt in this Final Rule, that party may exercise whatever rights it may have under the agreement or FPA section 206.

672. With regard to WECC's frequency-response concerns, we agree that a generator should be excused from imbalance penalties that occur due to directed reliability actions by generators to correct frequency. It would not be appropriate to assess imbalance charges on generator deviations that are associated with supporting system reliability by responding to frequency deviations as directed by the transmission provider or general reliability requirements. As such, if a response from a generator (particularly in the West) is required to prevent frequency decay and the corresponding deviations from the generator's schedule would cause additional imbalance penalties, the transmission provider should exempt the generator from those penalty charges.

b. Intentional Deviations

NOPR Proposal

673. In the NOPR, the Commission noted that the Bonneville imbalance provision allows for greater charges when a customer has an ''intentional deviation.'' [396] The Commission sought comment on whether the *pro forma* OATT imbalance provision should provide for similar penalties for behavior that represents deliberate reliance on the transmission provider's generation resources, as opposed to scheduling errors, with such penalties being subject to prior notice and approval by the Commission and based on the facts and circumstances of the individual transmission provider.

Comments

674. Several entities contend that higher imbalance charges and penalties for deliberately leaning on the grid can be appropriate.[397] Imperial supports an imbalance provision that allows for greater charges for persistent or patterned deviations. Pinnacle agrees that deliberate reliance on the transmission provider's generation resources is inappropriate and could adversely affect the reliability of the transmission system, but they are unsure if such an intentional deviation could be proven. Imperial also expresses concern that the burden to prove the intent of the generator will fall on transmission providers and that, in reality, transmission providers may face an uphill battle to prove a generator's deviation was intended. South Carolina E&G and Imperial request that the Commission provide a specific process for imposing such penalties, including what procedures should be followed if a transmission provider seeks to have the Commission impose such penalties.

675. Several entities oppose penalties for intentional deviations or suggest modifications. Constellation supports an elimination of the separate penalty structure for customers deliberately leaning on the system. Constellation and Grant believe that a graduated percentage adder/discount will provide the right incentives and disincentives without the need for an intentional deviation provision. If deviation costs are properly calculated, Morgan Stanley contends that requiring those who deviate to pay the full marginal cost of that deviation would result in fair allocation of cost responsibility and sufficient stability of system operations as a result of both cost and risk avoidance by participants. TDU Systems argue that the Commission should eliminate the 100 mill per kWh floor for penalties for intentional deviations.

Commission Determination

676. The Commission recognizes the need to provide transmission customers with the appropriate incentives not to intentionally dump power on the system or lean on other generation. We do not believe, however, that separate penalties for intentional deviations need to be generically imposed in the *pro forma* OATT. The tiered imbalance penalties adopted in this Final Rule generally provide a sufficient incentive not to engage in such behavior. Proposals to assess additional penalties for intentional deviations will continue to be considered on a case-by-case basis, subject to a showing that they are necessary under the circumstances. We note that any such tariff provisions must include clearly defined processes for identifying intentional deviations and the associated penalties.

c. Calculation of Incremental Cost

NOPR Proposal

677. With respect to the pricing of energy and generation imbalances, the Commission stated in the NOPR its belief that charges based on incremental costs or multiples of incremental costs would provide the proper incentive to keep schedules accurate without being excessive. The Commission proposed that incremental cost be defined to include both energy and commitment [398] costs, to the extent additional commitments are needed.[399]

[396] *See* 2006 Transmission and Ancillary Service Rate Schedules, approved in *United States Dep't of Energy—Bonneville Power Administration,* 112 FERC ¶ 62,258 (2005). The Bonneville tariff provides that ''For any hour(s) that an imbalance is determined by [Bonneville] to be an Intentional Deviation: (1) No credit is given when energy taken is less than the scheduled energy, (2) When energy taken exceeds the scheduled energy, the charge is the greater of: (i) 125% of [Bonneville's] highest incremental cost that occurs during that day, or (ii) 100 mills per kilowatthour.'' An ''Intentional Deviation'' is defined as ''a deviation that is persistent during multiple consecutive hours or at specific times of the day,'' a ''pattern of under-delivery or over-use of energy,'' or ''persistent over-generation or under-use during Light Load Hours, particularly when the customer does not respond by adjusting schedules for future days to correct these patterns.'' *Id.* at 46.

[397] *E.g.,* Imperial District Irrigation, Progress Energy and Ameren.

[398] The Commission noted that ''capacity commitment'' is generally defined as the generating capacity committed by a utility to provide capability for another utility to attain its reserve level. *See, e.g., Central & South West Services, Inc.,* 48 FERC 61,197 at 61,731 n.9 (1989).

[399] The Commission proposed defining incremental cost, based on its decision in *Consumers,* as the transmission provider's actual average hourly cost of the last 10 MW dispatched to supply the transmission provider's native load, based on the replacement cost of fuel, unit heat rates, start-up costs, incremental operation and

The Commission sought comment on how such charges should be calculated, as well as how they would be applied to transmission customers. The Commission sought further comment as to how additional demand and energy costs, if incurred in responding to imbalances, such as redispatch, commitment, or additional regulation reserves, should be appropriately reflected in the calculation of imbalance charges and which customers should be charged for such costs.

Comments

678. Several entities argue that incremental pricing for both energy imbalances and generator imbalances should reflect the full incremental costs incurred by the transmission provider (*e.g.*, such as redispatch costs, capacity commitment costs or additional regulation reserve costs) resulting from the imbalance.[400] Allegheny questions whether the *Consumer's* definition is appropriate because ''the last 10 MW'' requirement is independent of the time of the scheduling deviation. Allegheny contends that the definition should be modified such that it specifically addresses the incremental dispatch to supply the transmission provider's load ''in the hour in which the imbalance occurs.''

679. Entergy argues that imbalance pricing on an hourly basis does not capture all of the costs and reliability risk to the transmission provider of over- and under-deliveries. Entergy states that the real-time regulation burden imposed by IPPs is similar to the real-time regulation burden imposed by loads, and loads are charged for this cost through a transmission provider's Schedule 3 Regulation and Frequency Response Service. Entergy asserts that the NOPR does not propose any recovery mechanism for the regulation burden imposed by IPPs, recognizing that Bonneville may not face significant generator regulation costs due to the rapid ramping rate and relatively low cost of hydroelectric resources. Entergy submits that its regional experience has demonstrated that generator regulation service is a necessity. Entergy states that its generator regulation service recovers charges for the generating capacity that Entergy must maintain on-line in order to respond to the moment-to-moment deviations between scheduled output and actual generation. Entergy explains that the charge compensates Entergy on a cost-basis for the generation capacity used by IPPs, while at the same time sending the appropriate economic signal that encourages generators to match their generation with their schedules.

680. In its reply comments, EEI argues that a transmission provider should be entitled to recover the cost of additional reserves needed to meet the increased reliability requirements resulting from the provision of the imbalance energy if the transmission provider generates additional energy to compensate for a load that schedules less energy than it takes or a generator that produces less energy than it schedules. EEI further contends that transmission providers should be permitted to include in their calculation of imbalance charges any other costs associated with committing a unit that is not on-line such as minimum run times, losses, *etc.*

681. Entergy opposes a single price for settling over-deliveries and under-deliveries. For transmission providers who choose to base energy and generator imbalance charges on incremental and decremental costs, Entergy requests that the Commission not adopt standardized definitions of incremental cost and decremental cost in the *pro forma* OATT. In its reply comments, Entergy further argues that a requirement that the transmission provider post incremental and decremental cost information is unfair and harmful to the market, placing the transmission provider at an unfair competitive disadvantage in the market. Duke on reply proposes that System Incremental Cost (SIC) be used to price both over-deliveries and under-deliveries. Duke defines SIC to mean the incremental expense, measured in dollars per megawatt hour, incurred by the utility to produce or procure the next megawatt hour (MWh) of energy, after serving all of the utility's electric energy and/or capacity sales. Duke proposes that SIC shall include but not be limited to: The replacement cost of fuel; incremental operating and maintenance costs; emissions allowance replacement costs and other environmental compliance costs; the cost of starting and operating any generating units, (including costs incurred due to minimum runtimes or loading levels); purchase and interchange power costs; and all applicable taxes or assessments based on the revenues received or quantities sold.

682. Allegheny states that the Commission should clarify that the definition of incremental cost is equally applicable to intermittent generator imbalance service as well as non-intermittent generator imbalance service.

683. Pinnacle and Utah Municipals request that the Commission allow the use of alternative pricing methodologies, such as market proxy pricing methodology based on trading hubs in or adjacent to their respective control areas, where appropriate. Utah Municipals urge the Commission to make clear in the final rule that market-based pricing may be acceptable in some circumstances and to amend Schedule 4 of the *pro forma* OATT to ensure that imbalance charges are designed not only to provide legitimate incentives for accurate scheduling, but also to avoid unjustified penalties (masquerading as ''incentives''), to minimize the discriminatory impact of such charges, and to avoid penalizing behavior or results that in fact help to keep the system as a whole in balance.

684. TDU Systems believe the Commission should disallow recovery of demand charges or capacity commitment costs in any charges approved for imbalances. TAPS and TDU Systems argue that capacity required to follow load is already paid for by charges for regulation and reserves under Schedules 3, 5 and 6. TDU Systems also support that the Commission continue to apply its existing policy of imposing a heavy burden on transmission providers to justify such demand or capacity commitment charges in the context of a full base rate case, and of requiring transmission providers to develop alternative solutions for balancing schedules and loads.

685. To the extent transmission providers are permitted to include commitment costs in negative imbalance charges, Entegra believes that additional monitoring would be needed, to include posting of hourly imbalance charges, even if with a lag of a day or so. Suez Energy NA contends that the Commission should require a transmission owner to support its incremental cost filing on the basis of Form No. 423 data and actual operations of the selected units, based on operational data as reported in utilities Continuous Emission Monitoring reports.

686. EEI argues that since Schedule 3, 5 and 6 charges recover the costs of capacity based on test year data, they would not recover the additional costs of reserves that transmission providers incur to compensate for their customers' failures to match their schedules and their loads or generator output, and they also do not recover other commitment costs such as start-up costs or minimum run times. EEI argues that if transmission providers could not recover such costs through imbalance

maintenance costs, and purchased and interchange power costs and taxes.

[400] *E.g.*, Allegheny, Ameren, Indicated New York Transmission Owners, and FirstEnergy.

charges, they would not be able to recover them at all.

Commission Determination

687. The Commission concludes that it is appropriate to define incremental cost, for purposes of the tiered imbalance provisions adopted above, as the transmission provider's actual average hourly cost of the last 10 MW dispatched to supply the transmission provider's native load, based on the replacement cost of fuel, unit heat rates, start-up costs, incremental operation and maintenance costs, and purchased and interchange power costs and taxes, as applicable.

688. In deriving such charges, we note that the Commission proposed in paragraph 244 of the NOPR that incremental cost be defined to include both additional energy and commitment costs. The Commission also sought comment on how additional demand and energy costs, such as redispatch, commitment, or additional regulation reserves, would be appropriately recovered if incurred in responding to imbalances.

689. The Commission finds that it is appropriate, through the definition of incremental cost, to allow for recovery of both commitment and redispatch costs while excluding the cost recovery of additional regulation reserve costs. Commitment and redispatch costs shall be accommodated as a part of the hourly cost of the last 10 MW dispatch and in the start up cost portion of the definition. The Commission concludes that excluding additional regulation costs as a general matter is appropriate since much of those costs would be demand costs.[401] We believe including charges for unit commitment costs (*e.g.*, start-up and minimum load costs) and O&M costs is necessary to ensure that both energy and generation imbalance charges reflect the full incremental costs incurred by the transmission provider. We emphasize, however, that such costs should only be the additional costs incurred by the transmission provider due to the imbalance. If applicable, start-up costs should be allocated *pro rata* to the offending transmission customers based on cost causation principles.

690. If the transmission provider elects to have separate demand charges assigned to customers for the purpose of recovering the cost of holding additional reserves for meeting imbalances, the transmission provider should file a rate schedule and demonstrate that these charges do not allow for double recovery of such costs. To address Entergy's concern that the real-time regulation burden imposed by IPPs is similar to the real-time regulation burden imposed by loads, we will allow transmission providers to propose separate regulation charges for generation resources selling out of the control area and consider such proposals on a case-by-case basis. We believe that the other demand costs of providing imbalance service are already being provided under Schedule 3, 5, and 6 charges.

691. In responding to Allegheny's comments, we clarify that the definition of incremental cost is equally applicable to intermittent generator imbalance service as well as non-intermittent generator imbalance service.

692. We do not believe it appropriate to require transmission providers to use market proxy pricing to calculate incremental costs in the *pro forma* OATT. The feasibility of using market proxies must be considered on a case-by-case basis, given the characteristics of each market. If proposed, the proxy price must represent a valid alternative to the incremental cost calculation, reflecting competitive, transparent and liquid conditions similar to those that would exist in the seller's market.[402]

d. Inadvertent Energy Treatment

NOPR Proposal

693. The Commission proposed in the NOPR to continue to allow inadvertent energy to be treated differently from energy and generator imbalances, explaining that these two types of service are not comparable. The Commission noted that, given the nature of inadvertent energy and historical practices, transmission providers pay back inadvertent energy imbalances and that the Commission has accepted this practice as just and reasonable. The Commission sought comment on whether the current return-in-kind approach to inadvertent energy encourages leaning on the grid in times of shortage and, therefore, whether any reforms in this area are appropriate. The Commission asked whether pricing inadvertent energy at incremental cost (or some variant thereof) would be an appropriate disincentive and, if any reforms in this area are appropriate, whether they should be pursued under FPA section 215 as part of the review of reliability standards.

Comments

694. A number of commenters support continuing to allow inadvertent energy to be treated differently from energy and generator imbalances, agreeing that these two types of services are not comparable.[403] Allegheny argues that this historical practice makes sense because the variables germane to inadvertent interchange are beyond the control of individual transmission providers and, therefore, are best addressed in the context of reliability. Entergy notes that transmission customers have some flexibility to mitigate the deviations between their schedules and the operation of their load in real-time, while control area interchange imbalances may involve the failure of control areas to match their scheduled inflows and outflows due to contingencies occurring even in a third control area.

695. Northwest IOUs argue that there is no reason to think that there is abuse of one system leaning on another in regards to inadvertent energy, particularly in light of Control Performance Standards 1 and 2 and other protocols for balancing flows across interconnections. Public Power Council states that in-kind return of inadvertent energy between Balancing Authorities is governed by numerous agreements and tariffs that are designed to limit the ability of one system to lean on another.

696. Sacramento states that the Commission expressed concern in other settings that generators may intentionally undergenerate during high-cost hours and make it up by overgenerating during low-cost hours under a return-in-kind approach. Sacramento contends that in kind means not only a return of energy, but a return of energy at like times and conditions and does not believe that this results in leaning. In its reply comments, Exelon requests that the Commission's imbalance penalty rules explicitly prohibit the local utility Balancing Authority operator from relying on inadvertent energy to balance its affiliated generators' schedules and thus obtaining a competitive advantage.

697. Other commenters disagree that inadvertent energy should continue to be treated differently. Exelon expresses concern that in regions without organized markets there is the potential

[401] To the extent a transmission provider wishes to recover costs of additional regulation reserves associated with providing imbalance service, it must do so via a separate FPA section 205 filing demonstrating that these costs were incurred correcting or accommodating a particular entity's imbalances.

[402] *See RockGen Energy, LLC*, 100 FERC ¶ 61,261 (2002) (setting for hearing, *inter alia*, whether proposed market proxy price is reliable, verifiable, and also indicative of the prevailing price in liquid non-redispatch markets in the region).

[403] *E.g.*, Entergy, Allegheny, Progress Energy, Public Power Council, South Carolina E&G, PGP, and Ameren.

for local utility balancing authority operators to seek to avoid paying deviation charges by favoring their own generators over merchant generators or by using inadvertent energy to balance their schedule. Exelon argues that a balancing authority operator could maintain system balance by choosing to order its affiliated generators to deviate from the schedule and thereby allow its affiliated generator to avoid deviation charges that the merchant generator could not avoid. If the local utility balancing authority operator relies on inadvertent energy to balance its affiliated generators' schedules, Exelon contends it is using an option that is unavailable to other generation resources and obtains a competitive advantage.

698. TDU Systems argue that energy imbalances and inadvertent interchange may occur for many of the same reasons, *e.g.*, telemetry failure, meter error, generator governor response to system problems, human error, and under- or over-supply of generation. TDU Systems state that deviations between load and supply, whether in the form of energy imbalances or inadvertent interchange, require adjustment or compensation, but there is no reason why the form of that adjustment or compensation should be different among transmission users. TDU systems explain that NERC's Final Report of the Control Area Criteria Task Force describes inadvertent interchange as one of the ''strong incentives'' driving the newer market participants, such as independent generators, to become control areas, and driving existing control area operators to retain their functions.

699. TDU Systems explain that as the Commission acknowledged in Order No. 2000, for transmission providers in RTO regions, unequal access to balancing options can lead to unequal access in the quality of transmission service. TDU Systems oppose deferring consideration of inadvertent interchange issues until the Commission's order in the Mandatory Reliability Standards rulemaking proceeding in Docket No. RM06–16–000. TDU Systems argue that the Commission should place energy imbalance service on a footing as nearly comparable to inadvertent interchange as feasible by allowing like-kind exchanges of energy, at the incremental cost of their own supply portfolio, to remedy imbalances in lieu of the present paradigm of punitive charges.

700. TDU Systems also argue that the Commission should require comparability between transmission providers and transmission customers by imposing charges for inadvertent interchange at the suppliers' incremental cost. FirstEnergy believes that the Commission should establish a tiered penalty structure that, similar to the Bonneville method discussed by the Commission, levies penalties based on the severity of the inadvertent energy violation. TDU Systems state that currently there are no penalties for under-supply even when one control area could be deemed to be intentionally ''leaning'' on the grid to arbitrage energy market prices; but there should be.

701. FirstEnergy argues that a nationwide process should be established by the Commission to eliminate regional differences in the treatment of inadvertent energy. Constellation asks the Commission to require that transmission providers specifically separate imbalances from inadvertent energy and closely track and report the two.

Commission Determination

702. As stated in the NOPR, the Commission finds that inadvertent energy is not comparable to energy and generation imbalances and, therefore, we will continue to allow inadvertent energy to be treated differently from energy and generation imbalances. Inadvertent energy represents the difference between a control area's net actual interchange and the net scheduled interchange. It is caused by the combined effects of all the generation and loads in the control area and generation and loads outside of the control area. Variables affecting inadvertent interchange often depend on the actions or the omissions of utilities other than the individual transmission providers and are distinct from those resulting in energy and generation imbalances.

703. We also note that management of inadvertent energy is needed to adhere to NAESB standards. Historically, transmission providers have paid back inadvertent interchange imbalances in kind, which has not, as a general matter, proven to be problematic. Our primary concern with respect to inadvertent energy is to avoid incentives that could degrade reliability. To date, the return-in-kind approach has proven to be adequate as a general matter. However, if there is evidence that it is no longer sufficient to maintain reliability, or is allowing certain entities to lean on the grid to the detriment of other entities, the Commission has authority under FPA section 215 to direct the ERO to develop a new or modified standard to address the matter.

e. Netting/Crediting of Energy and Generator Imbalances

NOPR Proposal

704. In the NOPR, the Commission sought comment on whether or not it is appropriate to allow a transmission customer to net energy and generator imbalances for a particular transaction within a single control area to the extent they offset.[404] The Commission asked whether the potential to allow netting for offsetting imbalances contradicts the principle of encouraging good scheduling practices. The Commission sought further comment on what would be a reasonable percentage to net without concerns that allowing such netting would lead to reliability concerns from using unscheduled transmission or would cause redispatch costs by the transmission provider.

705. The Commission also proposed to add provisions to schedule 4—Energy Imbalance Service and schedule 9—Generator Imbalance Service of the *pro forma* OATT to reflect the Commission's policy that a transmission provider may only charge a transmission customer for either hourly generator imbalances or hourly energy imbalances for the same imbalance, but not both.[405] The Commission explained that this policy only applies to a transmission customer that otherwise would be charged for both generator imbalances and energy imbalances for the same imbalance occurring within the same control area.

Comments

706. A number of entities believe that transmission customers should be permitted to net energy and generator imbalances to the extent that such imbalances offset.[406] Ameren and FirstEnergy assert that netting better reflects the impact of imbalances. Morgan Stanley argues that allowing such netting provides a clear competitive benefit because it would allow competitive suppliers to offer a load following service in competition with the transmission provider. Sacramento agrees that netting of offsetting imbalances should be allowed

[404] For example, the Commission noted that a transmission customer scheduling 100 MWh over an hour, but with a load of 120 MWh, would face an imbalance of 20 MW. The Commission questioned whether there should be a net charge if the customer also dispatched its generation to the same 120 MWh. Similarly, what if a transmission customer schedules 100 MWh, but has a load of 80 MWh and dispatches its generation to 80 MWh?

[405] Imbalance Provisions Proceeding at 32,123 note 19 (*citing Niagara Mohawk*, 86 FERC ¶ 61,009 at 61,028).

[406] *E.g.*, Ameren, FirstEnergy, Xcel, Suez Energy NA, Morgan Stanley, Sacramento, TDU Systems, and Utah Municipals.

provided the transmission customer relies on reasonable load forecasts.

707. Utah Municipals and Steel Manufacturers Association argue that the Commission should impose charges based on netted imbalances, both for each customer and across the system as a whole. PGP contends that there is no reason to charge for both imbalances if a generator overruns during the same hour when a load overruns, so long as the overruns cancel out within a given control area. Steel Manufacturers Association contends that the Commission should incorporate control area-wide netting of imbalances to ensure that penalties are only assessed on significant imbalances and energy imbalance charges do not become a windfall profit center for utilities. Utah Municipals suggest that the Commission provide that all imbalances be netted for each hour and that penalties (charges above or credits below actual costs) be imposed only when the system as a whole is out of balance by more than a *de minimis* amount and, even then, only on those customers whose imbalances fall in the same direction as the system imbalance. Utah Municipals note that Sierra Pacific has established a similar imbalance mechanism, which appears to be working well in its control area.

708. TDU Systems argue that the netting rules should be sufficiently flexible to allow individual customers to net their transactions within an hour, a day, a week or a month, so long as the results keep the transmission provider economically whole. TDU Systems state that the Commission should not impose a cap on the quantity of netting allowed unless the transmission provider is able to demonstrate that good system performance requires such a cap. Ameren suggests that the Commission use a tiered system for determining when imbalances can be netted, but argues that a transmission customer should not be allowed to net offsetting imbalances elsewhere on the system if the imbalance has the potential to have a significant reliability impact.

709. FirstEnergy and Utah Municipals contend that both point-to-point and network transactions should be eligible for netting. Utah Municipals and NRECA in their reply comments note that the Commission's reference to ''a particular transaction'' does not mesh with the needs and practices of network customers, who do not attempt to match portions of their total hourly loads with particular resources or ''transactions.'' Utah Municipals argue that the Commission's proposal should be modified to make clear that such customers should be permitted to net energy and generator imbalances within a single control area to the extent they offset, with no requirement that the imbalances be part of a single ''transaction.''

710. Other commenters, however, contend that transmission customers should not be permitted to net energy and generator imbalances.[407] For example, Entergy and Pinnacle believe that to permit netting of energy and generator imbalances is to undercut the very purpose of the imbalance provisions, which is to provide adequate incentives to schedule correctly and in accordance with good utility practice. Pinnacle asserts that, depending upon the location, energy or generator imbalances could create reliability or economic problems for specific areas of the system and it is important that the transmission operator know what is happening on its system and for the customer to adhere to accurate scheduling. SPP argues that allowing netting of imbalance energy between generation and load would allow price arbitrage that would be unjust and unreasonable. Indicated New York Transmission Owners assert that positive and negative imbalances do not actually offset, as the NOPR would suggest, but rather each imbalance independently places stress on the transmission system. Duke states on reply that, although several commenters support netting imbalances, not one entity supporting such netting has put forth a workable proposal for how to implement such netting where multiple generators are serving multiple loads.

711. Entergy believes that independent generators must take full responsibility for meeting their own schedules, including making adjustments to their schedules to conform them to their operation in real-time. Entergy argues that a netting approach, however, would provide an incentive for a generator to over-generate above its schedule if its load proves to be greater than expected in real-time. Entergy argues that allowing the netting of these imbalances will result in the virtual elimination of transmission schedules.

712. In instances in which transmission customers intentionally game the transmission system through netting, FirstEnergy contends that the transmission provider should have the ability to apply punitive measures through a Commission-mandated penalty process. FirstEnergy states that there appears to be no clear cut number which defines the boundary between ''good'' netting and ''bad'' netting associated with reliability issues and additional redispatch cost. During periods when transmission constraints exist, Entergy contends that it may in fact be ramping up some generators to respond to imbalances while ramping down other generation to respond to other imbalances at exactly the same time and, therefore, it is incorrect to assume that over-generation supplied by one IPP accompanied by under-generation from another IPP, even simultaneously, will have no operational effect or impose no costs on a transmission provider.

713. Allegheny believes that allowing netting of hourly deviations inside the first deviation band on a monthly basis would not allow for full recovery of imbalance costs because balances that occur in on-peak periods cost more than imbalances that occur during off-peak periods. Allegheny contends that deviations within the first band should be measured and settled financially on an hourly or, at least, an on-peak/off-peak basis, rather than allowing deviations during one part of the month to be offset by deviations in another part of the month. Indianapolis Power & Light Company argues that the imbalance volume could be within the allowed bandwidth tolerance, but still be significant enough to allow for the energy market participant to make money off of the price difference.

714. Entergy also contends that a crediting mechanism for generator imbalances would be not appropriate. Entergy asserts that such a credit would result in indifference by generators by largely immunizing them from the costs resulting from their imbalances and, as a consequence, produce economic inefficiencies and a potential threat to system reliability. Entergy argues that the current method, which provides an incentive to generators to control their own imbalances, is appropriate because generators have a desire to accurately schedule to avoid imbalances. Entergy argues that a non-offending generator in one hour can be an offending generator in the next hour and that the credit will bankroll generators so that penalty payments in one hour will be offset and paid for by penalty receipts in another hour.

Commission Determination

715. The Commission recognizes that there is a trade off between the competitive benefits of reducing imbalance charges, including allowing transmission customers to net energy and generation imbalances, and the reliability implications of the transmission provider needing to plan to accommodate such imbalances.

[407] *E.g.*, Entergy, Pinnacle, Indianapolis Power, and Indicated New York Transmission Owners.

Allowing transmission customers to net imbalances would further comparability between the transmission provider's dispatch and the transmission customers serving load. However, netting and crediting could lessen the incentive for accurate scheduling and resulting energy or generator imbalances could create reliability or economic issues for specific areas of the system if the transmission provider cannot adequately plan for such imbalances.

716. In weighing these tradeoffs, the Commission concludes that for both energy and generator imbalance services it is not appropriate to require transmission providers to allow netting of imbalances outside of the tier one band. We agree that netting can cause problems because netting would lessen the incentive for transmission customers to schedule accurately, and inaccurate schedules, in turn, could require actions by the transmission provider even when the imbalances offset. Where transmission constraints exist, a transmission customer whose load and generation was on net equal could still have an effect on the transmission system if, as Entergy contends, some generation is ramping up to respond to some imbalances while other generation is ramping down at exactly the same time. Similarly, where transmission constraints exist, if one IPP has a positive deviation from its schedule while another IPP has a corresponding negative deviation from its schedule, the transmission provider could need to ramp up generation in one area while simultaneously ramping down generation in another area. Further, we believe that flexible scheduling deadlines should allow transmission customers to change their schedules such that their loads can be accurately met and implementation of the tiered imbalance bands will ensure that charges corresponding to imbalances are just and reasonable.

f. Intra Hour Netting

NOPR Proposal

717. Under the current *pro forma* OATT, energy imbalances occur when there is a difference between the scheduled and the actual delivery of energy to a load located within a control area aggregated over a single hour. As a result, if a transmission customer is under its scheduled level for the first half of a given hour, but over its schedule the second half of the hour, there would be no imbalance charge. The Commission did not address intra hour netting in the NOPR.

Comments

718. Several commenters argue that the Final Rule should address within-hour deviations that occur when generator imbalances are calculated on an integrated hour basis.[408] If the generator imbalance is measured over an integrated hour, as is typical of the current practice, TVA asserts that significant intra-hour swings may be masked.

719. South Carolina E&G states that generators, unable to ramp precisely to the 15-minute schedules, often undergenerate in the initial part of the hour, then overgenerate in later parts of the hour, in order to integrate closer to the schedule when settled over the entire hour. South Carolina E&G contends these intentional swings burden the balancing authorities who are charged with continuously keeping Area Control Error within predefined limits. International Transmission argues that intentional swings in output can be quite severe, imposing operational strains on the system, negatively impacting the control area's ability to meet NERC Control Performance Standards, and potentially jeopardizing reliability.[409] Entergy agrees that settling hourly energy imbalances with generators does not provide adequate incentives for generators to schedule and dispatch accurately within the hour. Entergy asserts that generators have imposed significant moment to moment swings within the hour requiring it to deploy its regulating reserves in response. Entergy states that it has been increasingly difficult to meet NERC's operating criteria for control area performance without committing, and incurring the costs for, additional regulating reserves. TVA contends that all generators should be required to ensure that the instantaneous generation level equals the scheduled output. International Transmission asks that the imbalance provisions in the Final Rule address this situation by either specifying penalties that may be assessed for within-hour variations or advising that transmission providers may implement their own penalties to the extent that within-hour variations cause operational difficulties.

720. South Carolina E&G contends that allowing generator imbalance settlements over a shorter period, such as at 15-minute intervals, together with the proposed tiered charges for imbalances, would provide better, more refined incentives for generators to more closely match their scheduled deliveries and would help balancing authorities reduce Area Control Error excursions. TVA suggests generator imbalances be measured on ten-minute intervals rather than integrated over an hour. These ten-minute imbalances would not be netted against other imbalance intervals, so as to avoid the problem of encouraging undergeneration followed by overgeneration and vice versa. In addition to having generator imbalance charges for generation outside the operating bands, TVA argues that there should be a separate charge assessed based on the peak generator imbalance between the scheduled and actual generation recorded instantaneously during the clock hour to provide a further incentive for proper generator scheduling.

721. Pinnacle and Utah Municipals assert that a transmission provider should only charge hourly generator imbalances or hourly energy imbalances for the same imbalance. PGP argues that customers should pay only one charge for the net imbalance that occurs within a single control area, either energy or generation, unless congestion occurs inside a control area that requires redispatch.

Commission Determination

722. The Commission concludes that it is appropriate to maintain the *status quo* of aggregating net generation over the hour in the *pro forma* OATT. Requests by transmission providers to adopt a shorter interval will continue to be considered on a case-by-case basis.[410] The Commission acknowledges that shorter intervals may be appropriate in particular circumstances and, for this reason, declined to use a clock-hour interval in the Large Generator Interconnection Final Rule.[411] There, the Commission permitted use of an interval ''consistent with the scheduling requirements of the Transmission Provider's Commission-approved Tariff and any applicable Commission-approved market structure.''[412] Allowing transmission providers to continue to propose alternative intervals for purposes of the *pro forma* OATT imbalance provisions is therefore appropriate provided that such proposals are consistent with relevant market structures.

[408] *E.g.,* TVA, South Carolina E&G, and International Transmission.

[409] International Transmission provides the example that a large generator with scheduled output of 100 MW for an hour might stay at zero for the first 50 minutes of the hour and then generate 600 MW during the last ten minutes.

[410] *See Entergy Services, Inc.,* 102 FERC ¶ 61,014 (2003) and *Entergy Services, Inc.*, 111 FERC ¶ 61,314 (2005).

[411] *See* Order No. 2003 at P 335.

[412] *See pro forma* LGIA Article 4.3.1

g. Distribution of Penalty Revenues Above Incremental Cost

NOPR Proposal

723. The Commission also sought comment in the NOPR regarding the treatment of revenues the transmission provider receives above the cost of providing the imbalance service.

Comments

724. Various commenters state that the transmission provider should retain any amounts above the incremental cost of providing imbalance service. Ameren and Constellation argue such revenues should serve as a contribution towards the fixed costs of providing this service. Entergy argues that premium charges would compensate it for the administrative costs of maintaining an organization capable of providing this purchase and sales function and provide generators with an incentive to avoid mismatches between scheduled quantities and actual deliveries to Entergy. Entergy states that the Commission has previously recognized that these generator imbalance charges are analogous to the economy power rates that have historically included a percentage adder for out-of-pocket costs to recover difficult-to-quantify costs.

725. On the other hand, FirstEnergy states that the additional revenue derived from charges above incremental costs should be provided to generators and/or customers able to regulate load that provided the redispatch, commitment, or additional regulation reserves. Utah Municipals contend that the Commission should credit revenues from charges above incremental costs to accurately-scheduling customers, rather than to the transmission provider. Utah Municipals argue that the penalty portion of incremental and decremental charges and rates could be credited back to all transmission customers who incur imbalance charges and whose schedules fell within the first deviation band for that hour. Progress Energy suggests that all imbalance revenues above the cost of providing the imbalance should be distributed to all non-offending transmission customers, based on the weighted amount of each non-offending transmission customer's usage of the transmission provider's transmission system. TAPS and TDU Systems ask on reply that penalty revenues not be earmarked for retail customers.

726. Morgan Stanley believes that imbalance charges should be ''keep whole'' charges calculated and designed to reimburse whoever remedied whatever problem the imbalance caused while leaving the transmission provider financially indifferent.

Commission Determination

727. In this Final Rule, the Commission has reformed existing imbalance provisions to reduce the variety of different methodologies used for determining imbalance charges and ensure that the level of the charges provide appropriate incentives to keep schedules accurate without being excessive. We also believe that transmission providers should have a consistent method of treating revenues received through imbalance penalties or charges that are in excess of incremental cost. The Commission has previously required transmission providers with significant imbalance penalties to develop a mechanism to credit penalty revenues to non-offending transmission customers.[413] This was intended to remove the incentive of the transmission provider to hinder the development of other imbalance services that do not rely on penalties.[414] We believe it is appropriate to maintain the requirement that transmission providers credit revenues in excess of incremental costs. Therefore, as part of their compliance filings in this proceeding, transmission providers are required to develop a mechanism for crediting such revenues to all non-offending transmission customers (including affiliated transmission customers) and the transmission provider on behalf of its own customers. Such a distribution of penalty revenues recognizes that transmission providers bear the responsibility to correct imbalances and often use their own facilities to do so.

728. We acknowledge that in the *CP&L* decision, the Commission declined to allow the transmission provider to allocate a share of imbalance penalty revenues to itself as a user of the transmission system on behalf retail customers. Given the reforms to the *pro forma* OATT imbalance provisions adopted in this Final Rule, we believe the circumstances presented in that case are no longer applicable. There, the Commission based its holding on its understanding that the high imbalance penalties imposed by the transmission provider were an interim measure that were intended to be in place only until an imbalance market was developed.[415] In this Final Rule, we are adopting imbalance charges that are closely related to incremental cost and therefore minimize any incentive on the part of the transmission provider to rely on penalty revenues rather than seeking other methods of encouraging accurate scheduling. Under these circumstances, there remains no reason to exclude the transmission provider from receiving an appropriate share of penalty revenues.

3. Credits for Network Customers

729. In Order No. 888, the Commission established that network customers should be eligible for credits for customer-owned transmission facilities under certain circumstances. Specifically, section 30.9 of the *pro forma* OATT states that a network customer owning existing transmission facilities that are integrated with the transmission provider's transmission system may be eligible to receive cost credits against its transmission service charges if the network customer can demonstrate that its transmission facilities are integrated into the plans or operations of the transmission provider to serve its power and transmission customers. Section 30.9 also states that new facilities are eligible for credits when the facilities are jointly planned and installed in coordination with the transmission provider.

NOPR Proposal

730. In the NOPR, the Commission proposed severing the link in the *pro forma* OATT between joint planning and credits for new facilities owned by network customers because such linkage can act as a disincentive to coordinated planning. The Commission proposed deleting from section 30.9 the language that permits transmission providers to refuse crediting for new network customer-owned facilities that are not part of its planning process, and adding language that puts a greater emphasis on comparability. Specifically, the Commission proposed that the network customer shall receive credit for transmission facilities added subsequent to the effective date of the Final Rule in this proceeding provided that such facilities are integrated into the operations of the transmission provider's facilities and if the transmission facilities were owned by the transmission provider, they would be eligible for inclusion in the transmission provider's annual transmission revenue requirement as specified in Attachment H of the *pro forma* OATT.

731. In the NOPR, the Commission also declined to allow transmission providers as part of this proceeding to automatically add costs of credits to the transmission provider's cost of service. However, the Commission stated that a

[413] *See Carolina Power & Light Co.*, 103 FERC ¶ 61,209 at P 25 (2003) (*CP&L*); *Entergy Svcs.*, 105 FERC ¶ 61,319, *reh'g denied*, 109 FERC ¶ 61,095 at P 65–66 (2004).

[414] *See Carolina Power & Light Co.*, 97 FERC ¶ 61,048 at 61,279 (2001).

[415] *Id.*

transmission provider may propose to add an automatic adjustment clause to its rates in a filing submitted under section 205 of the FPA. The Commission also explained that it would not propose to make credits generically available to point-to-point customers that own transmission facilities, but clarified that if some facilities owned by a point-to-point customer meet all the criteria for credits, consistent with the Commission's statement in Order No. 888, the Commission would address such situations on a fact-specific, case-by-case basis.[416]

a. Severance of Credits and Planning

Comments

732. The NOPR proposal to sever the link between transmission credits and joint planning by eliminating the joint-planning requirement for credits for new facilities constructed by network customers is supported by a cross-section of the industry.[417] Exelon asserts that linking credits to network customers with coordinated planning simply creates an incentive for the transmission provider to avoid coordinated planning with the network customers so that the provider can avoid providing credits. In addition, the criterion of ''jointly planned'' with the transmission provider provides little or no value for discerning what facilities should qualify for crediting treatment. Further, Exelon argues, tying credits to joint planning is no longer necessary because the Commission's regional planning initiatives will insure that most, if not all, newly constructed facilities will be jointly planned. While EEI disagrees that the joint planning provision has acted as a disincentive to joint planning, it agrees that the coordinated planning initiatives in the NOPR has made the link unnecessary.

733. FMPA also argues that the link between credits and planning discourages joint planning because companies can avoid transmission rate credits, often for competitors, by simply refusing to jointly plan. FMPA asserts that it makes no sense to create economic disincentives to joint planning. According to these commenters, transmission lines cannot be built without some exchange of information; the joint planning link may discourage the most productive exchange and can create needless and non-productive disputation over whether joint planning did or should have taken place.

734. PGP points out, however, that credits for new facilities can only result from joint planning, because new facilities must be interconnected with the existing grid, and planning studies are necessary for that to happen. NorthWestern requests that the Commission reconsider its proposal to allow crediting of customer-owned facilities that have not been jointly planned with the transmission provider. NorthWestern contends that allowing the construction of network facilities and making a judgment after the fact is inefficient and will result in protracted litigation and facilities that do not serve the overall grid as efficiently as planned facilities. PNM–TNMP contends that the Commission's proposed action to ''sever the link'' will excuse the network customer from the coordinated planning process and can only operate at cross-purposes with the coordinated transmission planning goal that is addressed in the planning sections of the NOPR.

Commission Determination

735. The Commission adopts the NOPR proposal to sever the link in the *pro forma* OATT between joint planning and credits for new facilities owned by network customers. The proposal received broad industry support, and we agree with these commenters that the link between credits for new facilities and the requirement for joint planning can act as a disincentive to coordinated planning, which is contrary to the Commission's original objective in adopting the provision. A transmission provider has an incentive to deny coordinated planning in order to avoid granting credits for customer-owned transmission facilities.

736. We find that arguments against the proposal are largely theoretical and do not adequately take into account the coordinated planning provisions proposed in the NOPR. The coordinated planning initiatives that the Commission is adopting in the Final Rule will ensure that most, if not all, transmission facilities are planned on a coordinated basis, making it unnecessary to retain this provision of section 30.9.

b. The New Test to Determine Eligibility for Credits

737. Comments support the test for new facilities proposed in the NOPR.[418] Some argue that the test for network customer credits should continue to be whether the network customer's facilities provide capability and reliability benefits to the grid—the same standard that would apply to inclusion of the facilities in the transmission provider's cost of service if the transmission provider constructed the facilities.[419] MidAmerican states that further clarification of this point in the Final Rule would be beneficial in minimizing disputes over this issue. Likewise, MidAmerican asks the Commission to clarify in the Final Rule that such credit can be applied only to network customers taking OATT service and not to transmission customers that are under non-OATT (*i.e.*, grandfathered bundled agreements) contracts. PGP supports the new rules for granting credits to network customers, but argues implementation details should be left up to individual transmission providers.

738. Although several transmission providers support the continued use of the integration test,[420] other commenters representing municipal and public power interests ask that the Commission reconsider or clarify its application.[421] Some commenters argue that given the Commission's current interpretation of ''integration'' for transmission credit purposes and the historical application of the test, retaining any integration requirement for existing or new facilities conflicts with comparability or constitutes undue discrimination.[422] TDU Systems argue that the integration standard has encouraged discriminatory behavior by allowing transmission providers to charge network customers for transmission provider facilities constructed to serve the transmission provider's native load, while refusing to pay the network customer for comparable customer-owned transmission facilities. TDU Systems further argue that the integration test has resulted in a form of ''and'' pricing since the TDU Systems, as network transmission service customers, remain obligated to pay their load ratio share of the full transmission revenue requirement of the transmission provider's system, including the cost of transmission facilities built to serve the transmission provider's own loads.

739. NRECA questions the Commission's statement in the NOPR that, in order to satisfy the integration

[416] Order No. 888 at 31,742; Order No. 888–A at 30,271.

[417] *E.g.,* Allegheny, East Texas Cooperatives, ELCON, Exelon, FMPA, MDEA, MidAmerican, MISO, Suez Energy NA, Tacoma, TAPS, and Utah Municipals.

[418] *E.g.,* Allegheny, EEI, Exelon, MISO, Nevada Companies, South Carolina E&G, Suez Energy NA, and Tacoma.

[419] *E.g.,* Allegheny, Ameren, and MidAmerican.

[420] *E.g.,* EEI, MidAmerican, and Nevada Companies.

[421] *E.g.,* FMPA, NRECA, and TAPS.

[422] *E.g.,* East Texas Cooperatives, NRECA, TAPS, and TDU Systems.

standard, a customer ''must demonstrate that its facilities not only are integrated with the transmission provider's system, but also provide additional benefits to the transmission grid in terms of capability and reliability and can be relied on by the transmission provider for the coordinated operation of the grid.'' [423] According to NRECA, that statement identifies three nominal requirements for customer facilities—integration, benefits and ''relied upon''—as compared to the one nominal requirement for transmission provider facilities—integration. This is fundamentally inconsistent with comparability, NRECA continues, as the Commission seems to recognize in its rationale for adding the comparability requirement to new facilities.

740. NRECA further argues that the NOPR failed to distinguish the proposed new standard in revised section 30.9 from the Commission's recent decision in *North East Texas Electric Cooperative, Inc.,*[424] which found transmission provider facilities integrated on the grounds that a showing of any degree of integration is sufficient, rejected a ''benefits'' requirement, and did not consider a ''relied upon'' requirement. East Texas Cooperatives argues that the Commission's decision in *East Texas Electric Cooperative, Inc.* v. *Central and South West Services, Inc.,*[425] applied an integration requirement for customer facility credits that was different and stricter than the standard applied to a transmission provider's facilities.

741. Regarding the application of the integration component, FMPA argues that, in order to avoid continued discrimination, it is important that the Commission reaffirm that ''additional benefits to the transmission grid in terms of capability, delivery options, and reliability'' [426] are benefits, regardless whether the transmission customers or the transmission provider (or others) benefit. Similarly, FMPA continues, the requirement that facilities must ''be relied upon for the coordinated operation of the grid'' [427] must equally include operations that serve transmission providers, customers or others.

742. Comments on the comparability component of the proposed credits test for new facilities range from several requesting that the Commission adopt a comparability-driven analysis [428] to one asking the Commission to eliminate the comparability component in favor of an integration-only analysis.[429]

743. Some commenters argue that eligibility for credits should turn in the first instance on the comparability standard set forth in the NOPR, otherwise the proposal does not eliminate undue discrimination.[430] NRECA argues that this requirement does not abandon integration because current Commission policy requires a Transmission Provider's facilities to be integrated for their cost to be rolled in to the transmission provider's annual transmission revenue requirement.[431] APPA would apply an integration test only if the transmission facilities for which the customer seeks credits are found not to be eligible under this comparability standard.

744. TAPS states that, by eliminating the integration test and simply providing that customer-owned facilities would be eligible for credits to the extent they would be included in the transmission provider's rate base if they were owned by the transmission provider (*i.e.*comparability test), the Commission would avoid litigation over what (if anything) the separate ''integration'' requirement adds in the proposed formulation. If the integration terminology is retained in section 30.9, TAPS argues that the Commission at least should clarify that the new integration test is truly different from the old integration test and cannot properly be read as limiting the comparability requirement and that the Commission will not follow precedents developed in credits cases decided under the original section 30.9.

745. To provide a comparability baseline and eliminate the need for an integration test, APPA recommends that transmission providers provide a detailed inventory of the existing facilities owned by transmission provider and network transmission customers that are included in their annual transmission revenue requirement. Network transmission customers could use the inventory, which would be updated annually, to assess whether they currently own transmission facilities comparable to those included in the transmission provider's transmission rate base, or to third-party transmission facilities for which credits are being provided.

746. MDEA argues that proposed section 30.9 appears contrary to comparability principles by imposing a standard for transmission facilities owned by customers that is more stringent than the one applied to the transmission provider's own facilities. In MDEA's view, the NOPR proposal is inconsistent with prior Commission precedent to the extent comparability is not required in evaluating eligibility of existing facilities owned by transmission providers for cost recovery.[432]

747. TDU Systems ask that the Commission clarify that the comparability prong will be aggressively enforced. For example, TDU Systems request that the Commission consider a bright-line voltage criterion to address comparability, rather than leaving it to the transmission provider's discretion as to whether the facilities would be eligible for inclusion in the transmission provider's annual transmission revenue requirement.

748. Arguing against the use of the comparability component, Entergy contends that it could cause significant confusion, and should in no way change the basic requirements needed to show integration of network customer facilities. According to Entergy, a network customer should be entitled to credits only when the transmission provider cannot meet the transmission provider's firm obligations without the customer's transmission facilities.

749. On reply, MDEA states that the principle of comparability requires that there be no distinction based on ownership or between existing and new facilities. It further asserts that Entergy attempts to draw a distinction between customer-owned transmission facilities needed by the transmission provider to meet the transmission provider's obligations to native load and firm transmission customers (for which credits should be available) and

[423] NRECA further notes that proposed OATT section 30.9 does not include these additional ''benefits'' and ''relied upon'' requirements. NRECA argues that these requirements cannot be part of the section 30.9, since regulatory preambles cannot vary the words of the rule, *citing Wyoming Outdoor Council* v. *U.S. Forest Service,* 165 F.3d 43, 53 (D.C. Cir. 1999) (''[L]anguage in the preamble of a regulation is not controlling over the language of the regulation itself'').

[424] 108 FERC ¶ 61,084 (2004), *reh'g denied,* 111 FERC ¶ 61,189 (2005).

[425] 114 FERC ¶ 61,027 at P 42 (2006), *appeal docketed,* No. 06–1090 (D.C. Cir. Mar. 10, 2006).

[426] NOPR at P 256.

[427] *Id.*

[428] *E.g.,* APPA, FMPA, and NRECA.

[429] Entergy.

[430] *E.g.,* APPA, East Texas Cooperatives, FMPA, and NRECA.

[431] NRECA compares *North East Texas Electric Cooperative, Inc.,* 108 FERC ¶ 61,084 (2004), *reh'g denied,* 111 FERC ¶ 61,189 (2005) (finding transmission provider facilities integrated and rolling in their cost over transmission provider objection) with *Mansfield Municipal Electric Department* v. *New England Power Co.,* 97 FERC ¶ 61,134 (2001), *reh'g denied,* 98 FERC ¶ 61,115 (2002) (finding transmission provider facilities not integrated and rolling out their cost over transmission provider objection).

[432] MDEA cites *Florida Power and Light Co.,* 116 FERC ¶ 61,013 (2006), and notes that the Commission applied principles of comparability to a transmission provider's existing facilities.

facilities that a network customer decides that it needs to meet its obligations. Entergy argues that credits should be available only for the former type of facility. According to MDEA, there is no justification for the distinction Entergy seeks to draw or the standard it proposes to apply. Network customers pay a full load ratio share of the embedded costs of the transmission grid, based on the premise that the entire grid is available and required to support network loads. In this regard, there is no difference between Entergy's native load and network customer loads. Transmission facilities required to meet network customer needs by definition are required to meet grid needs, provided that such facilities are integrated with the transmission network.

750. Several commenters ask the Commission to consider crediting mechanisms other than the NOPR proposal.[433] For example, Entergy and Exelon contend that new facilities should be eligible for credit only if determined through the regional planning process that such new facilities are needed, *i.e.*, that a measurable system capability or reliability benefit is provided. In their view, this will avoid litigation of cases addressing questions of integration. Utah Municipals argue that the Commission should not discount the potential evidentiary value of joint planning in assessing eligibility for customer credits. Taking a more expansive view, APPA argues that network transmission customers also should be able to obtain credits for transmission facilities they build pursuant to an open and collaborative transmission planning process in their region or sub-region. This additional opportunity for credits, according to APPA, would spur participation in the transmission planning process and would be superior to litigating the proper application of the integration standard.

751. Entegra argues that the Commission should make the crediting policy for network customers consistent with the Commission's policies for generator interconnection facilities, and require credits to be available for facilities that are integrated with the transmission grid, without any showing of additional benefits and irrespective of whether the service in question is interconnection service, network service, or point-to-point service. Entegra further argues that the Commission should allow customers to sell transmission credits to obtain transmission service elsewhere on the transmission provider's system. By allowing the development of a more liquid market for such credits, Entegra reasons, the Commission could increase the willingness of market participants to fund upgrades to the transmission system.

752. TDU Systems request that the Commission recognize that inequities have occurred and, if any upgrades are required to make network customers' facilities comparable (or comparably integrated), the costs of such network upgrades should be rolled into the transmission providers' rates.

Commission Determination

753. The Commission declines to adopt the credits test for new facilities proposed in the NOPR. The intent underlying that proposal was to prevent application of the integration test in a manner that exclusively benefits the transmission provider.[434] After reviewing the comments, we conclude that the proposed test may not in fact accomplish this objective. The test proposed in the NOPR may not effectively set forth the relationship of the integration standard to the comparability requirement. We therefore revise the test as follows, to more accurately reflect the Commission's intent as expressed in the NOPR: A network customer shall receive credit for transmission facilities added subsequent to the effective date of the Final Rule if such facilities are integrated into the operations of the transmission provider's facilities; provided however, the customer's transmission facilities shall be presumed to be integrated if the transmission facilities, if owned by the transmission provider, would be eligible for inclusion in the transmission provider's annual transmission revenue requirement as specified in Attachment H of the *pro forma* OATT.

754. Under our precedent, a transmission provider's facilities are presumed to provide benefits to the transmission grid, whereas a transmission customer must make an affirmative showing that its facilities provide benefits in order to qualify for credits.[435] Under the test we adopt in this Final Rule, a transmission customer will be required to meet the integration standard under *pro forma* OATT section 30.9 in order to receive a credit for its facilities.[436] Because joint planning will no longer be required in order to obtain credits, we find that it is particularly important in this context to require a showing that a network customer's facilities provide benefits to the transmission provider's grid, *i.e.*, a transmission customer should not be eligible for credits for facilities that the network customer may use to provide service for itself but that the transmission provider does not need to use to provide transmission service to any other customer. However, to ensure comparability, a presumption of integration will be afforded to transmission customer facilities if it is shown that, if owned by the transmission provider, such facilities would be eligible for inclusion in the transmission provider's rate base.

c. Application of the New Test to Existing Facilities

Comments

755. Several commenters object to the Commission's proposal to apply the new comparability test in section 30.9 to new facilities, and not to existing facilities.[437] If the Commission requires the same integration standard for both existing and new facilities, East Texas Cooperatives ask us to specify which integration standard—the pre-existing integration standard, or the new standard that applies the integration standard comparably—applies and explain the difference and the basis for that choice. MDEA, FMPA and TAPS argue that no distinction is warranted between the treatment of new and

[433] *E.g.,* Entergy, Exelon, and Utah Municipals.

[434] See NOPR at P 256.

[435] *See e.g., North East Texas Electric Cooperative, Inc.,* 108 FERC ¶ 61,084; *East Texas Electric Cooperative, Inc.* v. *Central and South West Services, Inc.,* 114 FERC ¶ 61,027.

[436] The integration standard, in brief, requires that to be eligible for credits under *pro forma* OATT section 30.9, the customer must demonstrate that its facilities not only are integrated with the transmission provider's system, but also provide additional benefits to the transmission grid in terms of capability and reliability and can be relied on by the transmission provider for the coordinated operation of the grid. *Southwest Power Pool, Inc.,* 108 FERC ¶ 61,078 at P 17 (2004) (*citing* Order No. 888–A at 30,271), *reh'g denied,* 114 FERC ¶ 61,028 (2006). This policy is premised on the principle that ''just as the transmission provider cannot charge the customer for facilities not used to provide transmission service, the customer cannot get credits for facilities not used by the transmission provider to provide service.'' *Id.* at P 20 (*citing* Order No. 888–A at 30,271 & n. 277); *accord East Texas Coop., Inc.* v. *Central & South West Services, Inc.,* 108 FERC ¶ 61,079 at P 28 (2004), *reh'g denied,* 114 FERC ¶ 61,027 (2006); *Southern California Edison Co.,* 108 FERC ¶ 61,085 at P 10 (2004); *Northern States Power Co.,* 87 FERC ¶ 61,121 at 61,488 (1999); *Florida Municipal Power Agency* v. *Florida Power & Light Co.,* 74 FERC ¶ 61,006 at 61,010 (1996), *reh'g denied,* 96 FERC ¶ 61,130 at 61,544–45 (2001), *aff'd sub nom. Florida Municipal Power Agency* v. *FERC,* 315 F.3d 362 (D.C. Cir. 2003).

[437] *E.g.,* APPA, FMPA, MDEA, NRECA, and TAPS.

existing facilities and that the same standard should apply.

756. TAPS clarifies that it is not suggesting that the standard be applied retroactively to past uses, but rather prospectively to existing facilities, with the key consideration being when the claim for credits is brought and not when the facilities are constructed. TAPS argues that it cannot be claimed that the revised standard should apply only to new facilities because the comparability requirement is new. To the contrary, TAPS contends that comparability has been the theme and bedrock foundation of the Commission's transmission open-access requirement since its inception.

757. APPA argues that the Commission effectively acknowledges in the NOPR that transmission providers have failed to plan new facilities jointly with their transmission customers for the last ten years under the current section 30.9, but offers no redress for this past discrimination.

Commission Determination

758. We conclude that the new test for determining credits will apply only to transmission facilities added subsequent to the effective date of this Final Rule. A number of customer-owned transmission facilities have been developed, and resulting credits negotiated and litigated, under the prior test which the Commission determined to be just and reasonable at the time.[438] We find no basis for revisiting the Commission's determinations in those cases in this Final Rule. On a prospective basis, however, given the increased planning and coordination we require in the Final Rule, we believe it appropriate to apply the new test for determining credits.

d. Cost of Customer Facilities Automatically Included in Transmission Provider Cost of Service Without a Rate Filing

Comments

759. Several transmission providers argue that, contrary to the Commission's proposal, credits should be added automatically to the transmission provider's cost of service.[439]

760. MidAmerican argues that requiring the transmission provider to defer including the cost of the transmission credit until its next filed transmission rate case penalizes the transmission provider's shareholders who must unfairly bear the cost of providing the credit until the next rate case. If the Commission does not allow automatic rate recovery of the incremental cost of credits, MidAmerican continues, the Commission should clarify that the customer will not be allowed transmission facility credits until the rate adjustments are filed and accepted by the Commission. MidAmerican explains that such filings would examine only the new revenue requirements to be added and should not require a general rate case for the transmission provider's entire revenue requirement. Nevada Companies likewise argues that credits should not be granted to network customers if the recovery of those credits is not provided for in the revenue requirement.

761. TAPS agrees with the Commission's conclusion that it would not be appropriate in this rulemaking to allow transmission providers to automatically add costs of credits to their cost of service, and that such costs should continue to be evaluated as part of a regular transmission rate case (or recovered through an approved formula rate). APPA expresses concern that transmission providers may attempt to use the Commission's decision not to allow them to add the costs of credits associated with customer-owned transmission facilities automatically to their costs of service as a pretext for not granting such credits in the first instance (at least until they decide to file a new rate case). APPA continues that a transmission provider's decision not to exercise the option to file under FPA section 205 a new rate case or an automatic adjustment clause should not serve as a reason to allow it to decline to provide credits.

762. EEI explains that the customary basis for not allowing single-issue rate adjustments for new transmission facilities is that while one aspect of the transmission provider's costs may have increased, others may have decreased or load may have increased. This is not the case with respect to the inclusion of the transmission costs related to customer-owned facilities, EEI continues, since the existence of customer-owned facilities does not have any impact on the transmission provider's own cost of service. EEI concludes that a transmission provider should not be forced into what is essentially re-justifying its transmission cost of service simply because a customer receives a credit for the integration of its own facilities.

763. Some commenters also address the option currently open to transmission providers to add an automatic adjustment clause to their rates through a rate filing with the Commission.[440] EEI argues that if the concept of an automatic adjustment clause is just and reasonable for one transmission provider, it is equally just and reasonable for all transmission providers, and there is no need to adopt a case-by-case approach. EEI further requests that the Commission clarify that its policy is to accept rate adjustments that incorporate the costs that transmission providers incur to provide credits related to customer-owned facilities, provided that the rate adjustment methodology is just and reasonable. MidAmerican contends that the revenue requirement of the transmission provider and those of transmission customers should not be co-mingled, rather, consistent with Commission precedent, the burden is on the transmission-owning customer to demonstrate to the Commission that its cost of service and revenue requirement used to establish the amount of the credit are just and reasonable before it can receive credits. As for nonjurisdictional entities, MidAmerican explains that they may file for a declaratory ruling from the Commission regarding their revenue requirement.

764. Allegheny argues that if the Commission continues to deny transmission providers an automatic adjustment clause for these credits, it should, at a minimum, assure transmission providers that transmission credits will be recognized as a cost of service in FPA section 205 rate proceedings.

765. Entergy argues that the Commission should recognize that any filed agreement providing for payments of credits would be subject to the filed-rate doctrine.

Commission Determination

766. We are not persuaded to generically allow automatic recovery of the costs of credits associated with integrated transmission facilities to the transmission provider's cost of service. These costs typically are considered and evaluated as part of a regular cost of service review process. Automatic recovery of the costs of credits would be contrary to our long-standing policy concerning single-issue rate adjustments, a policy we decline to modify here.[441] Nevertheless, transmission providers continue to have the option to propose an automatic adjustment clause in their rates under

[438] *See East Texas Electric Cooperative* v. *Central and South West Services, Inc.,* 114 FERC ¶ 61,027 (2006).

[439] *E.g.,* Allegheny, EEI, MidAmerican, and Nevada Companies.

[440] *E.g.,* Allegheny, EEI, Exelon, and MidAmerican.

[441] *See, e.g., City of Westerville, Ohio* v. *Columbus Southern Power Co.*, 111 FERC ¶ 61,307 (2005).

FPA section 205 to address the time lag between incurring costs associated with credits and the transmission provider's next rate case.

767. Contrary to EEI's assertions, customer credits do not warrant an exception to the Commission's general policy regarding single-issue rate adjustments. EEI argues that customer credits should be treated differently because the existence of customer owned facilities, in EEI's view, does not have any impact on the transmission providers' own cost of service. Even if true, this fact would not obviate the Commission's policy. Regardless of whether the customer credit is deemed to impact the transmission provider's own cost of service, the costs it imposes may be offset by cost decreases in other areas, by load growth, or both. Allowing single-issue rate adjustments would enable a utility to increase the total rate charged by focusing solely on a single cost element, while avoiding scrutiny of all other determinants of the rate. The Commission has an obligation to ensure the justness and reasonableness of the total rate and it would be improper to allow a utility to raise rates by selectively focusing only on particular elements of its costs, while avoiding scrutiny of other rate inputs. The Commission has refused to allow such rate treatment except in the most limited of circumstances and we find no basis for deviating from that policy in this context. As explained above, a transmission provider that wishes to add an automatic adjustment clause to its rates may seek Commission approval for its methodology in a filing submitted under FPA section 205.

e. Point-to-Point Customers Not Eligible for Credits on Generic Basis

Comments

768. Several commenters support the Commission proposal to not make credits generically available to point-to-point customers that own transmission facilities.[442] APPA argues that if the frequency of cases seeking credits for facilities owned by point-to-point customers is high, then the Commission should reconsider its decision to use a case-by-case approach.

769. Some commenters encourage the Commission to clarify that point-to-point transmission customers that pay for upgrades should be compensated if such upgrades benefit the system.[443] PGP argues that customers be given credits if they meet the same conditions as network customers who would qualify. Additionally, Entegra contends that denying credits for upgrades funded by point-to-point customers would overlook the Commission's past warnings that a customer funding any new facilities integrated with the grid should be entitled to credits because a transmission system ''cannot be dismembered'' or examined piecemeal.[444]

Commission Determination

770. The Commission adopts the NOPR proposal not to make credits generically available for point-to-point customers that own transmission facilities. As the Commission explained in the NOPR, a network customer takes a usage-based service which integrates its resources and loads and pays on the basis of its total load on an ongoing basis. The transmission provider includes the network customer's resources and loads in its long-term planning horizon and the two parties coordinate operations of their facilities through a network operating agreement. In this way, network service is comparable to the service that the transmission provider uses to serve its own retail native load, and credits for certain integrated network facilities are appropriate. The point-to-point customer, however, does not purchase integration service, nor does it sign a network operating agreement with the transmission provider. Because of the inherent differences between point-to-point and network service, we therefore decline to require that transmission providers make credits generically available to point-to-point customers that own transmission facilities. If a particular facility owned by a point-to-point customer meets all the criteria for credits, we will continue to address such situations on a fact-specific, case-by-case basis consistent with the Commission's statement in Order No. 888.[445]

f. RTO and ISO Issues

Comments

771. Several RTOs or ISOs assert that they should not be required to comply with the crediting provisions because their respective planning processes and procedures are superior to or obviate the need for those set forth in the NOPR.[446] CAISO states that it does not oppose the Commission's proposal, provided that the Commission confirms that facilities cannot be integrated into CAISO's operations unless they are under CAISO's operational control, consistent with the Commission's prior rulings.

772. In Xcel's view, an RTO has no incentive to refuse to jointly plan to avoid paying a credit and there is thus good cause to allow an RTO to deviate from the language in the *pro forma* OATT relating to joint planning of new facilities in order to be considered for a facility credit. Xcel and International Transmission argue that RTOs should be allowed to incorporate network customer-owned facilities into RTO rates in the same manner as if they were constructed by a transmission owner, while ensuring against double recovery of both revenue requirements and network credits.

Commission Determination

773. The Commission concludes that it would not be appropriate at this time to generically exempt all ISOs and RTOs from the Final Rule requirements regarding credits for network transmission customers. We will address issues relating to network transmission customers credits in the RTO and ISO context in orders addressing OATT reform compliance filings submitted by each RTO and ISO. The Commission determined previously that the existing tariffs of certain RTOs and ISOs provide opportunities for transmission customers to receive credit or the equivalent (*e.g.*, Transmission Congestion Contracts, Firm Transmission Rights or Auction Revenue Rights) for building facilities or upgrades that are consistent with or superior to Order No. 888 requirements.[447] Each RTO and ISO will have the opportunity to show on compliance that this continues to be the case given the reforms adopted in this Final Rule.

[442] E.g., APPA, Bonneville, EEI, Exelon, FirstEnergy, Nevada Companies, and TAPS.

[443] *E.g.*, FirstEnergy, Seattle, and Suez Energy NA.

[444] *Citing Nevada Power Co.*, 101 FERC ¶ 61,036 at P 8 (2002).

[445] Order No. 888 at 31,742; Order No. 888-A at 30,271.

[446] *E.g.*, Indicated New York Transmission Owners, ISO New England, PJM, and SPP.

[447] For example, NYISO's tariff provides that a facilities study will contain a non-binding estimate as to the feasible Transmission Congestion Contracts (TCCs) resulting from the construction of new facilities. There, upon completion of the transmission upgrade and the first subsequent centralized TCC auction, the NYISO will determine the incremental TCCs associated with the upgrade. *See* section 19.4 ''Facilities Study Procedures'' of NYISO's tariff. Similarly, PJM's tariff provides that an interconnection customer that undertakes responsibility for constructing or completing network upgrades and/or local upgrades to accommodate its interconnection request will be entitled to receive the incremental Auction Revenue Rights associated with such facilities and upgrades subject to conditions. *See* section 46.1 ''Right of Interconnection Customer to Incremental Auction Revenue Rights'' of PJM's tariff.

Other issues

Comments

774. East Texas Cooperatives argue that the Commission should clarify that a network customer is entitled to transmission credits for its own transmission facilities and the facilities of member utilities for which the network customer arranges and pays for network transmission services. East Texas Cooperatives explain that a recent Commission decision [448] allows transmission credits only for facilities owned by the generation and transmission cooperative (G&T) and not for its individual members, which in its view is contrary to past Commission precedent.

775. FMPA asks that the Commission affirmatively state that it will exercise its jurisdiction to ensure that public power entities are compensated for transmission investment (including joint transmission projects) in the event of dispute with jurisdictional transmission providers. FMPA explains that the proposed revisions to section 30.9 may be insufficient to address all problems that may arise, especially in regions without an RTO or an existing compensation method. NRECA asks the Commission to prohibit RTOs and ISOs from using a non-public utility's transmission facilities without compensating the entity simply because it has not joined the RTO or ISO. NRECA argues that comparable treatment requires compensation for use of a transmission owner's facilities, whether the owner is subject to Commission jurisdiction or not, and the Commission should not consider a transmission tariff to be just and reasonable if it allows unlawful trespass and conversion.

776. TAPS asks the Commission to include language in section 30.9 of the *pro forma* OATT that affirmatively states customers' eligibility for rate incentives for new facilities under recently established Commission policy. TAPS further requests that the Commission guard against a transmission provider blocking such incentive based credits by refusing to engage in joint development of transmission projects with its customers.

Commission Determination

777. The Commission finds that there is not enough evidence on the record to make a generic determination on these issues and, instead, will address them on a case-by-case basis in response to appropriate filings under FPA sections 205 and 206. With regard to incentives for new facilities, the Commission has already addressed incentives for transmission infrastructure investment in Order No. 679.[449] There the Commission identified specific incentives that it will allow when justified in the context of individual proceedings. With regard to FMPA's concerns regarding potential disputes over compensation for transmission investment by non-public utilities, we note that section 12 of the existing *pro forma* OATT contains dispute resolution procedures. This Final Rule also requires transmission providers to propose a dispute resolution process as part of the coordinated planning process. Additionally, the Commission's Dispute Resolution Service is available to assist in developing a dispute resolution process, as well as the Commission via a formal complaint filed pursuant to section 206 of the FPA.

4. Capacity Reassignment

778. In Order No. 888, the Commission concluded that a transmission provider's *pro forma* OATT must explicitly permit the voluntary reassignment of all or part of a holder's firm point-to-point capacity rights to any eligible customer.[450] With respect to the rate for capacity reassignment, the Commission concluded it could not permit reassignments at market-based rates because it was unable to determine that the market for reassigned capacity was sufficiently competitive so that assignors would not be able to exert market power. Instead, the Commission capped the rate at the highest of (1) The original transmission rate charged to the purchaser (assignor), (2) the transmission provider's maximum stated firm transmission rate in effect at the time of the reassignment, or (3) the assignor's own opportunity costs capped at the cost of expansion (price cap). The Commission further explained that opportunity cost pricing had been permitted at ''the higher of embedded costs or legitimate and verifiable opportunity costs, but not the sum of the two (*i.e.*, 'or' pricing is permitted; 'and' pricing is not).'' [451] In Order No. 888–A, the Commission explained that opportunity costs for capacity reassigned by a customer should be measured in a manner analogous to that used to measure the transmission provider's opportunity cost.[452]

NOPR Proposal

779. In the NOPR, the Commission noted that capacity reassignment does not appear to have developed into a competitive alternative to primary capacity since the issuance of Order No. 888. To facilitate development of this market, the Commission proposed to remove the price cap on capacity reassignment and allow negotiated rates for transmission capacity reassigned by transmission customers. The Commission explained that, because the price cap appears to have reduced customers' transmission options, removal of the cap may be warranted without a market-by-market analysis. Due to market power concerns, however, the Commission proposed to retain the price cap for capacity reassigned by the transmission provider's merchant function or its affiliates.

780. The Commission proposed to monitor the market for reassigned capacity by requiring regular OASIS postings and quarterly reports from transmission providers using information submitted by reassigning customers. First, the Commission proposed retaining the existing posting and filing requirements for reassigned capacity transactions to ensure that capacity is equally available to all customers and to protect against undue discrimination and the potential exercise of market power.[453] Second, the Commission asked several questions regarding OASIS postings and the data that should be required in quarterly reports related to capacity reassignments: (1) What information should be required in the quarterly reports and OASIS postings, *i.e.*, information about the capacity released, the original rate paid for that capacity, the price charged to the assignee for the capacity, and the term of the assignment; (2) whether other information was necessary for operational and reliability purposes; (3) whether additional reports by assignors to the transmission provider are necessary and, if so, what information should be reported by assignors; (4)

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[448] *East Texas Electric Cooperative, Inc.* v. *Central and Southwest Services, Inc.*, 108 FERC ¶ 61,077 at P 21–23 (2004), *reh'g denied,* 114 FERC ¶ 61,027 at P 43–44 (2006), *appeal docketed,* No. 06–1090 (D.C. Cir. Mar. 10, 2006)

[449] *Promoting Transmission Investment through Pricing Reform,* Order No. 679, 71 FR 43294 (Jul. 31, 2006), FERC Stats. & Regs. ¶ 31,222 (2006), *order on reh'g,* Order No. 679–A, 72 FR 1152 (Jan. 10, 2007), FERC Stats. & Regs. ¶ 31,236 (2007).

[450] *See* Order No. 888 at 31,696; *pro forma* OATT section 23.1.

[451] *Id.* at 31,740.

[452] Order No. 888–A at 30,224.

[453] The existing OASIS posting requirements for reassigned capacity already require, if selling on OASIS, for sellers to include data elements such as the path name, point of receipt, point of delivery, source, sink, capacity requested, capacity granted, start time, stop time, and offer price. *See* 18 CFR 37.6(c)(5).

should the Commission establish a new quarterly reporting process with a new form, or use the existing Electric Quarterly Report procedures; and (5) how frequently should OASIS postings be made.

Comments

Lifting the Price Cap for All Transmission Customers

781. Some commenters support eliminating the price cap for reassignment of transmission capacity in the secondary market.[454] For example, EPSA states that the Commission is correct to recognize that negotiated rates are dynamic and provide a market discipline on the price for reassigned capacity. Entegra argues that the Commission's removal of rate caps on releases of natural gas pipeline capacity increased available peak capacity and facilitated the movement of capacity into the hands of those that value it most highly, proving that an uncapped capacity release market can be both competitive and result in just and reasonable rates for customers.[455] Exelon supports eliminating the price cap, but asserts that, since the transmission customer is seeking to reassign the capacity, it is likely the capacity is not useful in gaining access to load and therefore is not very valuable. BP Energy contends that transparent competition between the transmission provider (marketing primary and subscribed but unutilized capacity) and transmission customers, with monitoring by the Commission and prospective capacity purchasers, will moderate if not eliminate the potential exercise of market power and encourage the release of capacity that is not otherwise used or useful. As a result, BP Energy urges the Commission to require transmission providers to facilitate a competitive capacity reassignment process, similar to that used for capacity release on natural gas pipelines.

782. Some commenters support the proposal to retain the price cap for transmission providers and their affiliates.[456] Seattle states that the Commission is correct to continue to cap prices for the transmission provider since the transmission provider is a regulated monopoly. In its reply, Entegra states that the Commission has found that having a *pro forma* OATT mitigates but does not eliminate a transmission provider's ability to leverage its monopoly power in transmission into market power in generation markets.[457] Entegra further contends that Southern, Entergy, and other transmission providers have monopoly power in transmission markets in their service territories and without a cap would exploit that market power in the secondary market. Moreover, Entegra argues that allowing transmission providers and their affiliates to charge market-based rates for transmission capacity in the primary or secondary market would exacerbate the skewed incentives that already operate to discourage construction of much needed transmission facilities in many markets.

783. Many commenters contend that lifting the price cap for reassignment of transmission capacity only for unaffiliated transmission customers would be unreasonable.[458] For example, Entergy argues that for the wholesale markets to work all wholesale market participants, including the transmission provider's affiliated marketers, must be treated comparably under the *pro forma* OATT. EEI contends that lifting the price cap can result in a more robust secondary market for transmission capacity and will reduce any risks that transmission customers may associate with being required to purchase transmission service for five-year terms in order to obtain rollover-rights. In addition, Manitoba Hydro asserts that changing the current one-year minimum term creates additional risks for transmission customers and therefore having the ability to re-sell the transmission capacity at market-based rates would assist transmission customers to better manage the financial risks involved with holding longer term contracts.

784. Some commenters support lifting the price cap for affiliates if caps are removed for non-affiliates, but are only generally supportive of lifting the price cap.[459] If the Commission does lift the price cap, Southern argues that it should also lift the price caps for the transmission provider and its affiliates as well in order to counter efforts to corner the market and other related unforeseen consequences. MidAmerican agrees, asking the Commission to retain the cap for all transmission customers if the transmission provider and its affiliates are not allowed to resell capacity at market-based rates.

785. Several commenters argue that the Commission's justification for eliminating the price cap—namely, reducing the ability of non-affiliated customers to exercise market power in the secondary market through competition among releasing customers, monitoring the market via quarterly reports, and continuing rate regulation of primary capacity—applies to energy and marketing affiliates as well.[460] First, several commenters argue that the Standards of Conduct and existing *pro forma* OATT rules ensure that transmission provider affiliates have no more ability to obtain information about the transmission system or to reserve point-to-point transmission capacity than unaffiliated customers. [461] Entergy contends that, although the Commission correctly concludes elsewhere in the NOPR that functional unbundling and Standards of Conduct requirements, if properly enforced are sufficient to address affiliate abuse concerns, the Commission seems to assume that those same protections cannot be effective where the reassignment of transmission capacity is concerned.

786. Second, some commenters question the Commission's assertion that permitting transmission provider's energy and marketing affiliates to resell or reassign transmission capacity would give them the ability to favor their own generation.[462] For example, EEI contends that transmission providers have no control over the reassignment process, and transmission customers have complete freedom to reassign transmission capacity to any customer they choose. Entergy points out that under Order No. 888 the assignor of capacity may deal directly with an assignee and without involvement of the transmission provider.[463]

787. Third, some commenters disagree with the Commission's statement that lifting the price cap for affiliates may dampen transmission investment.[464] These same commenters argue that there is no relationship between the transmission provider's obligation to build transmission

[454] *E.g.*, Allegheny, AWEA, Constellation, EEI, Entegra, EPSA, Exelon, Morgan Stanley, PPL, Seattle, Suez Energy NA, and TranServ.

[455] *Citing Natural Gas Pipeline Negotiated Rate Policies and Practices,* 114 FERC ¶ 61,034 (2006) (Brownell, Comm'r concurring).

[456] *E.g.*, APPA, AWEA, NRECA, Seattle, TAPS, and TDU Systems.

[457] *Citing Public Service Electric & Gas Company,* 78 FERC ¶ 61,119 at 61,455 (1997) (granting market-based rate authority based in part on the adequate "mitigation of market power" as evidenced by a *pro forma* OATT).

[458] *E.g.*, Community Power Alliance, EEI, Entergy, FirstEnergy, Imperial, Manitoba Hydro, MidAmerican, Progress Energy, and Salt River.

[459] *E.g.*, MidAmerican, PNM–TNMP and South Carolina E&G.

[460] *E.g.*, EEI, Entergy, MidAmerican, PNM–TNMP, Progress Energy, Southern, and South Carolina E&G.

[461] *E.g.*, Community Power Alliance, Entergy, Imperial, Manitoba Hydro, Salt River, South Carolina E&G, and Southern.

[462] *E.g.*, EEI, Entergy, MidAmerican, and Progress Energy.

[463] *See* Order No. 888 at 31,697.

[464] *E.g.*, EEI, MidAmerican, and Progress Energy.

facilities to accommodate third party requests for transmission service and the ability of marketing and energy affiliates to resell unused transmission capacity at market-based rates. For example, Progress Energy and others contend that the transmission provider is obligated under the *pro forma* OATT to construct transmission facilities to meet all requests for transmission service.[465] Progress Energy and EEI contend that the transmission customer will decide to purchase secondary market transmission capacity if it meets the reasonable needs of customers so long as the capacity is priced below the higher of the embedded cost of transmission service or the cost of expansion. EEI argues that the customer can require the transmission provider to construct additional capacity to accommodate the customer's request for service if secondary market service—whether offered by the transmission provider's marketing and energy affiliates or by a third party customer—is priced above the cost of expansion. In such situations, EEI and Progress Energy contend that the cost of expansion serves as a cap on the price at which both third party customers and the transmission provider's marketing and energy affiliates can resell transmission capacity. Moreover, Entergy argues that this is the same justification that the Commission relies upon to conclude that transmission customers would not hoard secondary capacity, and it is arbitrary for the Commission to ignore that principle in concluding that a transmission provider would hoard capacity.

788. Additionally, some commenters argue that lifting the price cap for affiliates will encourage transmission investment.[466] NorthWestern contends that allowing transmission providers to collect more than their ceiling price when the market is willing to pay a higher price could further the Commission's goal of encouraging transmission investment to maintain reliability and keep pace with load growth. NorthWestern suggests that the Commission could place restrictions on the proceeds in excess of the ceiling price such that, within some specified period, the dollars must be reinvested into transmission facilities or be refunded back to customers.

789. Several commenters contend that lifting the price cap only for non-affiliates could dampen participation in the secondary market and place affiliates at a competitive disadvantage.[467] Community Power Alliance argues it is unfair for the Commission to now say that their separated marketing affiliates, which have abided by Commission rules like any other market participant, cannot now compete on an equal footing with other participants in the secondary market for transmission capacity. Rather than prohibit transmission providers' affiliates from reselling capacity, Manitoba Hydro suggests that a more equitable approach would be for the Commission to lift the price cap for all resold transmission capacity, except for transmission capacity administered by an affiliate's transmission provider.

790. To the extent the Commission adopts the proposed restriction on affiliate reassignments, MidAmerican seeks guidance on whether the transmission provider is expected to assure that the assignee is a valid eligible customer under the *pro forma* OATT. Similarly, Southern encourages the Commission to carefully identify and evaluate the possible adverse effects of lifting any reassignment price caps. Southern asserts that such effects could include expanded involvement and influence by financial players driven exclusively by profit motives and who may not be subject to Commission regulation.

791. Several commenters contend that the Commission should retain the price cap for the reassignment of transmission capacity for all customers, not just affiliates of the transmission provider.[468] APPA argues that allowing the resale of such a scarce and valuable service to those who value the capacity more highly is a recipe for undue discrimination and unjust and unreasonable transmission rates, at the expense of end-use customers. While NRECA opposes the Commission proposal to remove the price cap, NRECA would support the proposal to retain the price caps for affiliates. Similarly, TAPS supports the decision not to lift the price caps for affiliates; however, TAPS urges the Commission to rethink the NOPR's proposal to otherwise lift the price cap for non-affiliates.

792. Several commenters argue that lifting the cap for any transmission customers would encourage the exercise of market power, including hoarding, and discourage transmission investment.[469] If removal of the cap were effective in making reassignment more profitable, TAPS contends it would encourage hoarding of capacity on key paths that would run afoul of the directive in FPA section 217(b)(4) to ensure the ability of LSEs to secure long-term rights for their long-term power supply arrangements. Northwest IOUs argue that lifting the price cap would encourage non-affiliated transmission customers to buy transmission capacity at cost and resell it at market, in an effort to reduce the amount of transmission capacity available for resource development and other long-term uses. PJM argues that the final rule should include a requirement that appropriate hoarding mitigation procedures be implemented should the price cap be removed. APPA argues that, if no transmission capacity is available in the short run from the transmission provider, and an LSE needs additional capacity to serve load within the next day or week, the fact that the transmission provider could build capacity in future years at an incremental rate has little if any bearing on the price that LSE is willing to pay for the next day, week, or month to avert a looming supply problem. TVA asserts that transportation prices rose drastically during periods of high demand or constraint after the price cap for resale of gas transmission capacity was removed in Order No. 637 for everyone except pipelines and their affiliates. TVA states that this benefited entities that could afford to hold capacity, but harmed those that had to buy additional capacity on a short-term basis.

793. Alcoa and Nevada Companies argue that there is a significant potential for abuse in connection with the removal of the cap, particularly in load pockets. Alcoa argues that it is not clear at this point that there are sufficient safeguards in place to prevent and monitor the exercise of market power, something that must be assured before the cap is lifted on transmission capacity resale. Nevada Companies contend the proposal to remove the cap may actually reduce utilization of the grid, contrary to its intended purpose. For example, Nevada Companies state that transmission customers who have locked up capacity in constrained markets will likely wait to the very last minute to make that capacity available in order to drive up the price, which will often result in the capacity not being utilized if transactions cannot occur quickly enough. Some

[465] *E.g.*, EEI, Entergy and MidAmerican.

[466] *E.g.*, Entegra and NorthWestern.

[467] *E.g.*, Community Power Alliance, EEI, FirstEnergy, Imperial, Northwest IOUs, Southern, and TVA.

[468] *E.g.*, Alcoa, APPA, International Transmission, Nevada Companies, NRECA, PJM, Public Power Council, TAPS, and WAPA.

[469] *E.g.*, APPA, Nevada Companies, Northwest IOUs, NRECA, PJM, TAPS, and WAPA.

commenters contend that, like LMP in organized markets, allowing price signals via lifting the cap may not encourage transmission investment, but rather create entrenched interests that profit from the existence of congestion and oppose efforts to eliminate such congestion through transmission expansion.[470] If transmission providers are forced to purchase capacity at higher prices on the secondary market, Imperial argues that their native load customers be harmed by such higher prices, which may in turn hamper transmission expansion contrary to the Commission's stated goals for promoting transmission investment.

794. In addition, some commenters are skeptical of the Commission's assertion that existing market mechanisms are a sufficient deterrent to anticompetitive behavior.[471] WAPA and TAPS argue that, while eliminating the price cap might increase customers' transmission options, the Commission still needs to conduct case-by-case market power analyses prior to lifting the cap.[472] As a result, WAPA argues, it is critical for the Commission to identify and aggressively mitigate all transmission market power on an *ex ante* basis, rather than utilizing an *ex post* monitoring scheme as proposed in the NOPR. If the Commission lifts the price cap, certain commenters argue that the Commission should establish competitive bidding transaction standards.[473] For example, Seattle asserts that a standards organization such as NAESB will need to establish bid/ask transaction standards and reporting formats and the Commission must periodically validate the assumption that the secondary market is workably competitive.

Application of the Price Cap to Members of ISOs/RTOs

795. Some commenters request clarification that, if the Commission retains the price cap for capacity reassigned by affiliates, that it not apply to entities that have turned over control and operation of their transmission facilities to an RTO, ISO or independent entities.[474] For example, Constellation requests that the Commission clarify that the revised *pro forma* OATT does not impose the cap on affiliates of transmission owners that have turned their transmission facilities over to an RTO/ISO when they reassign transmission capacity on facilities operated by the RTO/ISO. While MISO takes no position on whether the Commission should retain its cap for stand-alone transmission providers and their affiliated customers, it argues that the cap makes no sense in the context of capacity reassignments administered by RTOs and ISOs. MISO observes that the NOPR cites affiliate preference and market power concerns as the basis for retaining the cap on reassignments by transmission providers and their affiliated customers, which MISO argues are not applicable in the RTO/ISO context. Further, MISO argues that the ownership of transmission assets in an RTO/ISO is divorced from the provision of transmission service, and RTO transmission owners are transmission customers no different from any other customer class.

796. On the contrary, APPA notes that the issue is whether the transmission customer holding transmission rights over a constrained path has the ability to exercise market power and charge unjust and unreasonable rates if the cap is lifted. APPA argues that the issue is the same in both RTO and non-RTO regions. In APPA's view, whether the public utility transmission provider has joined an RTO, does not affect the ability of its merchant affiliate to extract unjust and reasonable rents for the resale of scarce transmission rights.

Alternative Price Cap Proposals

797. Some commenters propose alternatives to negotiated pricing of transmission capacity in the secondary market.[475] While APPA supports retaining the current rate cap, it contends that firm point-to-point customers should be allowed to collect demonstrable out-of-pocket costs in addition to the maximum capped rate. Alcoa suggests that the Commission could stimulate the secondary market for transmission capacity by increasing the cap and allowing parties to charge a percentage over the original price paid. Seattle contends that the existing Commission policy could be incrementally modified to permit recovery of remarketing costs and recognize that, for many customers, the transmission right is held at a much higher per unit cost than the primary rate stated in the transmission provider's *pro forma* OATT (due in part to the fact that a customer may not use all of the capacity for which it has contracted).

798. Sacramento proposes that prices for released capacity be capped at the amortized and rate-based cost of a transmission upgrade. Seattle states that costly redirect processes, including system impact studies, may be needed to create a reassignment product that has value to other customers, given that the point of receipt, point of delivery or both typically change in a reassignment. While the current *pro forma* OATT pricing model differentiates transmission rates based on term and time of day (monthly, weekly, daily, hourly), Seattle asserts that seasonal variations in the value of transmission rights offered for short-term reassignment are also worthy of consideration, especially in a region like the Northwest, where power production varies seasonally.

799. MISO states that it believes the Commission should further strengthen its pro-competitive policy by permitting RTO/ISO transmission providers to offer firm point-to-point transmission service for drive-out/drive-through transactions at market-based rates, including ''rollover'' transactions. MISO states that the principles for allocating firm capacity on such interfaces should be the same as for reassigning capacity within an RTO: *i.e.*, permitting customers that value the capacity more highly to benefit from it. MISO asserts that allowing market participants to compete based strictly on price on external interfaces would resolve many inefficiencies stemming from the cumbersome queue administration procedures currently used on such facilities. MISO states that the final rule should encourage RTOs and ISOs to introduce such competitive practices in their footprints.

800. PGP proposes two alternative approaches. First, PGP proposes that the Commission could wait until a regional approach for pricing reassignments is developed in those areas of the country that still rely on reassignments of point-to-point capacity to create a secondary market in transmission service. Second, PGP proposes that any decision to remove the price cap could be made on a case-by-case basis after a filing by a point-to-point customer at the Commission, in which the applicant must meet standards developed by the Commission that demonstrate the lack of market power in relevant transmission or generator markets.

[470] *E.g.*, APPA, International Transmission, NRECA, Public Power Council, and Seattle.

[471] *E.g.*, Alcoa, APPA, Bonneville, TAPS, and WAPA.

[472] *Citing Farmers Union Cent. Exch., Inc.* v. *FERC*, 734 F.2d 1486, 1508–10 (D.C. Cir. 1984) (concluding that ''undocumented reliance on market forces is insufficient to satisfy the Commission's regulatory responsibilities.''); *California ex. Rel. Lockyer* v. *FERC*, 383 F.3d 1006, 1013 (9th Cir. 2004).

[473] *E.g.*, BP Energy, Seattle, and TranServ.

[474] *E.g.*, Ameren, Constellation, SPP, and TranServ. ISO New England and PJM argue that, as providers of transmission service, they have no affiliates and likewise are not bound by the Commission's reassignment proposal.

[475] *E.g.*, Alcoa, APPA, Manitoba Hydro, PGP, Sacramento, and Seattle.

801. South Carolina E&G requests that the Commission clarify how the cap is calculated if the Commission chooses to retain the price cap. International Transmission asserts that the Commission should lift the price cap, on an experimental basis, similar to the approach followed in the natural gas industry. Similarly, WAPA recommends that the Commission either retain the price cap or institute a separate rulemaking proceeding for the purpose of establishing detailed market analysis criteria for eliminating the price cap for specific transmission segments or paths.

Posting and Filing Requirements

802. Some commenters support the proposal to require transmission providers to submit quarterly reports and make OASIS postings regarding reassignments of transmission capacity.[476] Bonneville asserts that, at a minimum, transmission customers should be required to provide a downloadable file to the transmission provider for posting on the transmission provider's OASIS that identifies the assignee, the amount of capacity assigned or transferred, the date of the offer of assignment, and the rate and duration of the assignment. Other commenters argue that transmission customers should be given greater reporting responsibility.[477] Southern contends that transmission providers should not be burdened with submitting quarterly reports and making OASIS postings based on assignment information provided to them by other assignors/assignees. Rather, Southern and EEI argue that assignment information should be filed by the respective assignors and assignees in connection with their Electric Quarterly Report filings and not by the transmission provider. PNM–TNMP contend that the Commission should prescribe specific reporting obligations and associated deadlines to the assignors and reporting obligations should also include appropriate consequences for non-compliance on the part of the assignor. Nevada Companies ask that a system be put in place to charge relevant transmission customers for the additional reporting if the transmission provider is required to do the reporting, either on the OASIS or through some other mechanism.

803. Some commenters argue that more information should be posted on OASIS beyond what was proposed in the NOPR.[478] EEI asserts that the details the transmission customers should report on the OASIS and in the quarterly reports include: The identity of the primary market seller; the identities of the secondary market seller and purchaser; the points of receipt and delivery; the term of reassigned service; the quantity of the reassigned service; and the charge for the reassignment, expressed in dollars per MW-month, week, day, or hour as appropriate. Other commenters contend that the existing quarterly report is appropriate and a new report should not be instituted.[479] TranServ argues that the existing OASIS posting template query and audit functions are sufficient and no new obligations should be required. As to frequency of OASIS postings, Seattle suggests seven days after a transaction and NorthWestern proposes that the OASIS postings be no more frequent than monthly.

804. Other commenters raise confidentiality concerns or state that business practice standards for capacity reassignment posting requirements would be required.[480] Because these negotiated rates will be market sensitive, Allegheny asks the Commission not to require reporting and OASIS posting until the term of the reassignment has expired. NAESB states that capacity reassignment, including removing the price cap and allowing negotiated rates, could require posting standards for OASIS sites and the addition of significant functions to support such postings.

805. NAESB states that capacity reassignment including removing the price cap and allowing negotiated rates could require posting standards for the OASIS site, and significant functions added to support such postings. NAESB asserts that this will require a more comprehensive standards solution, which may include data aggregation by the transmission provider, reports prepared and posted quarterly including how the information is communicated between the transmission provider and marketer for collection, submittals of quarterly reports from the transmission provider to the Commission, changes to the OASIS S&CP, and determination of informational content and design of templates. NAESB states that posting is more complicated if the transmission provider is required to post information given to it by a marketer on its non-standard products and requests Commission guidance regarding posting requirements.

Other Issues

806. Some commenters argue that price caps are not limiting capacity reassignment under the current *pro forma* OATT.[481] Williams contends that other non-price limitations on capacity reassignment, such as the requirement that the assignee utilize the same source and sink as the original customers, are the real reasons there has not been more capacity reassignment. Williams acknowledges that this bars network customers from reassigning transmission capacity and requests that Commission clarify that classification of a transmission customer as a network or point-to-point customer does not restrict the purchase or reassignment of transmission capacity. Sacramento similarly complains that one of the chief impediments to capacity reassignment is that network integration service customers are not permitted either to assign their capacity or to utilize it to make off-system sales. Sacramento contends that a point-to-point customer may utilize otherwise unused capacity to make sales ''off-system'' to third parties, while network customers cannot make full use of the transmission capacity for which they are paying.

807. Some commenters contend that timelines for the release of capacity should be clearly stated.[482] APPA argues that section 13.8 of the *pro forma* OATT provides too little time for LSEs attempting to make firm power supply arrangements to obtain even daily firm point-to-point service using the capacity left unscheduled by other firm point-to-point customers. Powerex and SPP also ask the Commission to set out clear rules, including timelines, for releasing unused transmission capacity for non-firm use to better encourage full and economically efficient use of the existing transmission grid.

Commission Determination

808. To foster the development of a more robust secondary market for transmission capacity, the Commission concludes that it is appropriate to lift the price cap for all transmission customers reassigning transmission capacity. In Order No. 888, the Commission found that allowing holders of firm transmission capacity rights to reassign capacity would help parties manage the financial risks associated with their long-term commitments, reduce the market power of transmission providers by enabling customers to compete, and foster

[476] *E.g.*, Bonneville, FirstEnergy, and PJM.

[477] *E.g.*, EEI, Entergy, Nevada Companies, PNM–TNMP, South Carolina E&G, Southern, and TVA.

[478] *E.g.*, EEI, PJM, and Seattle.

[479] *E.g.*, PJM, PNM–TNMP, and TranServ.

[480] *E.g.*, Allegheny, Morgan Stanley, NAESB, Seattle, and TranServ.

[481] *E.g.*, Powerex, Sacramento, TAPS, and Williams.

[482] *E.g.*, APPA, Powerex, and SPP.

efficient capacity allocation.[483] Over the past ten years, however, it has become clear that capacity reassignment has failed to develop into a competitive alternative to primary capacity. In particular, the price cap has served to reduce customers' transmission options and impaired the development of a secondary market for transmission capacity. In order to achieve the goals originally stated in Order No. 888, we therefore lift the price cap for reassigned capacity. We believe this will allow capacity to be allocated to those entities that value it most, thereby sending more accurate price signals to identify the appropriate location for construction of new transmission facilities to reduce congestion.

809. We decline to adopt the NOPR proposal to retain price caps for capacity resold by a transmission provider's merchant function or its affiliates.[484] After reviewing the comments submitted in response to the NOPR, and further considering our ten years of experience regulating capacity reassignments, we conclude that retaining the price caps for this portion of the market would continue to impair development of the secondary market and is not otherwise necessary to ensure just and reasonable rates. We find there are no significant market power concerns to justify retaining the price caps for any transmission customer. Indeed, the Commission did not distinguish between affiliated and non-affiliated transmission customers when it initially found in Order Nos. 888 and 888–A that excess capacity reserved could be reassigned.[485] The Commission instead placed a price cap on all reassignments of capacity out of a concern that the entire market for reassigned capacity was not sufficiently competitive.[486] We now find that market forces, combined with the requirements of the *pro forma* OATT as modified in this Final Rule, will limit the ability of assignors to exert market power, including affiliates of the transmission provider. First, competition among reassigning customers will restrict the exercise of market power. Second, the continued regulation of rates for primary capacity will act as a further check to ensure rates for reassigned capacity remain just and reasonable. Finally, the amended rules we adopt below to govern the reassignment of capacity will increase our regulatory oversight of the secondary capacity market, allowing us to effectively monitor the secondary capacity market. There is thus no need to retain the existing price caps on reassigned capacity for any market participant.

810. Our decision to lift the price caps for capacity reassignments by all transmission customers is motivated by growing concerns regarding the decrease in transmission investment and the corresponding increase in congestion costs, as described more fully in section III.C of this Final Rule. The Commission believes it is important to take every opportunity to explore more efficient use of the grid by industry participants, whether they are affiliates of the transmission provider or not. Eliminating the price cap for reassigned capacity will provide greater flexibility to respond to changing system conditions and alternatives for customers that value the capacity more highly. As commenters suggest, lifting the price cap will enhance the ability of customers that reserve long-term capacity for five-year terms in order to obtain rollover rights to resell that capacity if their needs change.[487] Other customers may determine that it is more economic to acquire reassigned capacity reflecting market rates than reserve long-term capacity. In either case, lifting the price cap will help ensure that, during peak demand periods, transmission capacity will be used by those that value it the most. Establishing a competitive market for secondary transmission capacity will thus send more accurate price signals that promote efficient use of the transmission system by fostering the reassignment of unused capacity.

811. While some commenters argue that lifting the cap encourages the exercise of market power, including hoarding, and discourages transmission investment, we find that competition among reassigning customers, continuing rate regulation of the transmission provider's primary capacity, and reforms to the secondary capacity market adopted below, combined with enforcement proceedings, audits, and other regulatory controls, will assure just and reasonable rates. The Commission discussed the possibility of transmission capacity hoarding in Order No. 888. The Commission noted that unscheduled firm capacity is available on a non-firm basis to other customers and, thus, there is little practical possibility of hoarding. Instead, the capacity reassignment provisions of the *pro forma* OATT provide an economic incentive to make that capacity available to third parties.[488] This applies even when the entity obtaining transmission capacity under the *pro forma* OATT is the transmission provider.[489] It is equally in the corporate interests of a transmission provider and its affiliates not to over-reserve or ''hoard'' transmission capacity. Under the *pro forma* OATT, the affiliate—and therefore the upstream corporate parent of the affiliate and the transmission provider—bears the cost responsibility for transmission capacity that it reserves but does not use to make wholesale sales. If the affiliate attempts to hoard transmission capacity, its upstream corporate parent loses revenues just like the non-affiliate. Like any other customer, an affiliate of the transmission provider should find it in its overall corporate interest to reassign transmission capacity to others with higher valued uses at negotiated rates.[490]

812. We reject the suggestion in the NOPR that lifting the price caps for the transmission providers' merchant function or affiliates will provide disincentives to build or expand the transmission system. Without congestion, the transmission provider's rate on file will serve as the *de facto* price cap and, if congestion exists, the ''incremental rate'' reflecting the transmission provider's cost of expanding the system should act as a price ceiling for long-term transactions. It would be unreasonable to expect a transmission customer to pay a rate for reassigned capacity that is higher than the cost of expansion when it could simply exercise its rights under the *pro forma* OATT as a cheaper alternative. To the extent there is a lag-time between the request for new transmission service

[483] Order No. 888 at 31,696.

[484] Because Order Nos. 888 and 888–A require a separation of a public utility's transmission function and its wholesale generating marketing (merchant) function, a transmission provider will take service under its OATT through its merchant function or affiliate.

[485] Order No. 888 at 31,696–97; Order No. 888–A at 30,219–25.

[486] Order No. 888 at 31,697.

[487] As explained in section V.D.3, the Final Rule extends from one year to five years the minimum term required to obtain a rollover right.

[488] Order No. 888 at 31,693.

[489] *See Southwestern Public Service Company,* 80 FERC ¶ 61,245 at 61,905 (1997).

[490] Moreover, Order No. 889 required that all public utilities establish or participate in an OASIS that meets certain specifications and comply with Standards of Conduct designed to prevent employees of a public utility (or any employees of its affiliates) engaged in wholesale power marketing functions from obtaining preferential access to pertinent transmission system information. The Standards of Conduct mitigate the ability of an affiliate to hoard capacity or collect rates that are inconsistent with market conditions. As a result, we are less concerned in this instance about affiliates competing on the same terms as non-affiliates. To the extent problems arise from affiliate participation in the secondary capacity market, we will revisit our decision here to lift the price caps for transmission providers and their affiliates.

and the date on which new facilities would be available, the adoption of conditional firm service and modifications to redispatch service elsewhere in this Final Rule will mitigate the exercise of market power during the interim period. We believe that the reforms to rules governing reassignments of capacity discussed below, along with associated reporting obligations, will adequately limit the ability of capacity holders to exercise market power in the limited circumstances when neither primary transmission capacity nor these additional services are available.

813. Several commenters raise concerns that lifting of the price ceiling could lead to speculative pricing. If high prices occur during periods of peak demand it is a legitimate reaction to supply and demand forces. As we explained in Order No. 637–A, ''[a] surge in the price of candles during a power outage is not evidence of monopoly in the candle market.'' [491] To the extent that capacity is not being anticompetitively withheld from the market, high prices are the competitive responses to market conditions and should result in a more efficient allocation of capacity to those customers valuing it the most and a resulting expansion of transmission facilities.

814. We emphasize that we are not deregulating or otherwise adopting market-based rates for the provision of transmission service under the *pro forma* OATT. Transmission providers will continue to be obligated to make ATC available to customers, including ATC associated with purchased but unused capacity. Transmission providers also will continue to be obligated to construct new facilities to satisfy a request for service if that request cannot be satisfied using existing capacity. The *pro forma* OATT therefore does not, and will not, permit the withholding of transmission capacity in an effort to exercise market power. Furthermore, the rates for transmission service provided under the *pro forma* OATT will continue to be determined on a cost-of-service basis unless the transmission provider can demonstrate, on a case-specific basis, that it lacks market power. Nothing in this Final Rule affects the obligations of transmission providers to offer service under the *pro forma* OATT at cost-based rates. The only reform being adopted concerns the resale of capacity by transmission customers. Given that traditional regulation will continue to govern the sale of primary capacity under the *pro forma* OATT, we no longer believe that cost-of-service regulation is necessary or appropriate for secondary capacity.[492]

815. As with any innovative rate program, however, the Commission will monitor the secondary capacity market to ensure that participants are not exercising market power. To enhance oversight and monitoring by the Commission, we adopt reforms to the underlying rules governing capacity reassignments. First, we require that all sales or assignments of capacity be conducted through or otherwise posted on the transmission provider's OASIS on or before the date the reassigned service commences. The Commission thus eliminates the current ability of transmission customers to assign the transmission rights to another party with subsequent notification to the transmission provider.[493] The mechanisms for negotiating a reassignment remain the same. The transmission customer may either request that the transmission provider make the capacity available on its OASIS or the transmission customer may negotiate the terms of an assignment bilaterally. In either instance, however, the resulting sale or assignment must be posted by the transmission provider on its OASIS prior to the date the reassigned service commences. We require transmission providers working through NAESB to develop appropriate OASIS functionality to allow such postings. Transmission providers need not implement this new OASIS functionality and any related business practices until NAESB develops appropriate standards.

816. Second, we require that assignees of transmission capacity execute a service agreement prior to the date on which the reassigned service commences. Under the current *pro forma* OATT, transmission customers that have executed service agreements may negotiate and implement assignments of capacity without involving the transmission provider, subject to after-the-fact reporting and posting, provided the transmission customer has a market-based rate tariff on file.[494] In order to increase our oversight of reassigned capacity, we find that all reassignments must instead be accomplished by the assignee executing a service agreement with the transmission provider that will govern the provision of reassigned service.[495] This will effectively return the specified capacity to the transmission provider for the purpose of reassignment to the assignee.[496] The assignment shall be only to the specified assignee, without any obligation that the capacity be made available to third parties, and shall not be subject to any queuing by the transmission provider since the assignee is merely accepting the assignor's already-approved service for a specified period.[497] All of the non-rate terms and conditions that otherwise would apply to the transmission provider's sale of transmission capacity continue to apply in the case of a reassignment.[498]

817. Third, in addition to existing OASIS posting requirements, we require transmission providers to aggregate and summarize in an electronic quarterly report the data contained in these service agreements. As proposed in the NOPR, the use of quarterly reports will assist the Commission in gathering data to ensure the effectiveness of market forces and regulatory requirements to mitigate the exercise of market power. The Commission directs that this quarterly report be submitted electronically in spreadsheet format

[491] Order No. 637–A at 31,595.

[492] Our findings here address the particular circumstances associated with the electric utility industry and are not intended to suggest that corresponding changes should be made to the rates for capacity release by customers of natural gas transportation capacity. Any such changes would be considered only after notice and comment and based on a record applicable to the natural gas industry.

[493] *See* Order No. 888 at 31,697.

[494] *See* Order No. 888 at 31,697 n.394; Order No. 888–A at 30,224 n.151.

[495] The *pro forma* Form of Service Agreement for the Resale, Reassignment or Transfer of Long-Term Firm Point-to-Point Transmission Service is set forth in a new Attachment A–1 to the *pro forma* OATT.

[496] As reformed in this Final Rule, the structural mechanism for reassigning transmission capacity will be similar to the mechanism for releasing pipeline capacity. While parties may be able to negotiate the prices applicable to assigned capacity, the assignee will execute a service agreement directly with the transmission provider and, thus, there will no longer be a need for the assigning party to have on file with the Commission a rate schedule governing reassigned capacity. *See* Order No. 888 at 31,697 n. 324. The transmission provider's OATT will govern the reassigned service. The assignee will pay the transmission provider for service at the negotiated rate and the transmission provider will bill or credit the assignor with any the difference between the negotiated rate and the assignor's original rate. As noted above, however, there will be no requirement for the transmission provider to create an auction for reassigned transmission capacity similar to the pipeline capacity reassignment program, since the underlying price caps are being removed for electric transmission capacity.

[497] To the extent the assignee desires to change its points of receipt or delivery, the limitations set forth in section 23.2 shall apply.

[498] *See Commonwealth Edison Co.,* 78 FERC ¶ 61,312 at 62,336 (1997); *Boston Edison Co.,* 81 FERC ¶ 61,372 at 62,768 (1997); *Southwestern Public Service Co.,* 80 FERC ¶ 61,245 at 61,905 (1997). The non-rate terms and conditions of reassigned service will therefore conform to the *pro forma* OATT. As a result, there is no requirement to file with the Commission service agreements for reassigned transmission service.

consistent with the electronic filing system used for Electric Quarterly Reports so that it is readily accessible to the Commission and the public.[499]

818. Taken together, these reforms to the rules governing reassigned capacity will increase transparency and facilitate our monitoring of the secondary market for transmission capacity. We do not believe it is necessary to require a market power analysis as a condition to exercising the right to reassign transmission capacity. Although market power analyses are one method for ensuring that market-based rates remain just and reasonable, they are not the only method.[500] To achieve the Commission's original goals for capacity reassignment expressed in Order No. 888, we adopt a more flexible approach in this area and rely on posting requirements and other regulatory controls to ensure that rates for reassigned transmission capacity remain just and reasonable. As noted above, we find that a market power analysis is not required because transmission providers continue to be obligated to satisfy requests for service—whether out of existing capacity or new facilities—at cost-based rates. Transmission capacity therefore cannot be withheld in an effort to exercise market power. Moreover, the posting and filing requirements adopted herein provide the Commission the necessary information to ensure that, even if an entity sought to exercise market power in the secondary market, such an attempt could be effectively detected.

819. We therefore disagree with commenters who assert that lifting the cap on reassignment contradicts judicial and Commission precedent. In Order No. 637–A, the Commission explained at length why *Farmers Union*[501] and other precedent did not prevent the Commission from adopting negotiated rates for secondary capacity as part of a regulatory scheme that provides safeguards to ensure that rates remain just and reasonable.[502] The court affirmed the Commission's removal of price ceilings for short-term capacity release shippers in the natural gas market established in Order Nos. 637 and 637–A, recognizing that non-cost factors such as the need to lift price ceilings to facilitate movement of capacity into the hands of those who value it most and the negotiated rates only to the secondary market distinguished the case from *Farmers Union*.[503] The same is true here, given the non-cost factor advantages of lifting the price cap and the use of monitoring and enforcement of remedies to mitigate the exercise of market power.

820. The Commission directs staff to closely monitor the reassignment-related data submitted by transmission providers in their quarterly reports to identify any problems in the development of the secondary market for transmission capacity and, in particular, the potential exercise of market power. We direct staff to prepare, within six months of receipt of two years of quarterly reports, a report summarizing its findings. To inform our analysis, we encourage market participants to provide feedback regarding the development of the secondary capacity market and, in particular, to contact the Commission's Enforcement Hotline[504] with any particular concerns as this market develops.

821. Although several commenters argue that additional posting and filing requirements could be too burdensome and costly, the Commission does not believe this burden will be great. All capacity reassignments must be conducted or otherwise posted on OASIS and each assignee will be required to submit an executed service agreement for reassigned service. The transmission provider thus will have ready access to data necessary for the OASIS postings and electronic quarterly transaction reports. In any event, the Commission's access to this data is vital to ensure effective monitoring and oversight and, thus, we find that any burden on the transmission provider is outweighed by the need for transparency. To the extent the transmission provider incurs costs to maintain or report this information, Order No. 889 made clear that all OASIS users, including the transmission provider, pay all of the fixed costs of OASIS-related activities in wholesale rates and pay usage-related variable costs and fees.[505]

822. With regard to confidentiality concerns, the Commission finds that the disclosure of reassigned capacity information is necessary for the Commission and market participants to effectively monitor transactions for undue discrimination and preference. Consistent with our determination in Order No. 2001, where similar concerns were raised regarding disclosure of information, we believe that disclosure will promote competition and make the market operate more efficiently.[506] Moreover, public reports will provide customers with a certain level of price transparency to help them make informed decisions regarding the relative value of capacity on a particular path.

823. We decline requests to require implementation of electronic auctions for reassigned capacity. While such mechanisms are in place in RTO and ISO markets, we conclude that it would be too great a burden to impose electronic auctions on other transmission providers simply to facilitate capacity reassignments. The continued use of OASIS, combined with the posting and service agreement requirements adopted here, should be sufficient to facilitate more efficient use of the grid and mitigate the exercise of market power.

824. With regard to the requests that the Commission institute alternative specific timelines and other rules for the reassignment of capacity rights to ensure efficient use of the grid, we will not revise the rules set forth in the *pro forma* OATT. We do not have sufficient evidence in this proceeding to suggest that public utilities' existing scheduling timelines generally hinder customers from reselling unused transmission capacity or lead to capacity withholding.

825. With regard to requests for network customers to reassign transmission capacity, we affirm our finding in Order Nos. 888 and 888–A that capacity reassignments are available only to point-to-point customers.[507] Point-to-point service under the *pro forma* OATT clearly sets forth defined capacity rights and is therefore reassignable. In comparison,

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[499] The transmission provider should identify capacity reassignments in the Contracts tab of the EQR using the Product Type Name ''CAPACITY REASSIGNMENT.'' All terms must be fully described and rates provided. If no Product Name adequately captures the nature of a given aspect of the capacity reassignment, the assignor may use the Product Name ''OTHER,'' but that aspect must be fully described in the Rate Description field. If that description is over 150 characters, the transmission provider may use multiple Contract Product lines to describe it. General instructions on how to file the EQR may be found at *http://www.ferc.gov/docs-filing/eqr.asp*.

[500] *See Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines and Regulation of Negotiated Transportation Services of Natural Gas Pipelines,* 74 FERC ¶ 61,076 (1996).

[501] *Farmers Union Central Exchange* v. *FERC,* 734 F.2d 1486, 1501 (D.C. Cir. 1984) (*Farmers Union*) (finding that Commission failed to justify relaxation of cost-based regulation of oil pipeline companies because it did not ensure rates would remain within the zone of reasonableness).

[502] Order No. 637–A at 31,558–72.

[503] *Interstate Natural Gas Association of America* v. *FERC,* 285 F.3d 18 (D.C. Cir. 2002).

[504] Market participants may contact the Commission's Enforcement Hotline via telephone (202) 502–8390, toll-free 1–888–889–8030, fax (202) 208–0057, or at *http://www.ferc.gov/cust-protect/enforce-hot.asp*.

[505] Order No. 889 at 31,625.

[506] *See* Order No. 2001 at P 94–129.

[507] Order No. 888 at 31,696; Order No. 888–A at 30, 223.

there are no specific capacity rights associated with network service and, thus, that service is not reassignable. Network service provides a network customer with a right to integrate its designated resources with its designated loads, in a generation pattern primarily determined by the customer. As a result, it would be difficult to determine at any moment in time exactly what portion of network service could be resold, because the network customer does not have a discrete capacity reservation and its usage of the transmission system varies as it attempts to most economically use its resources to meet its loads. To the extent an entity elects network service, it does so with the understanding that the service is not reassignable because there are no specific capacity rights to reassign.

5. ''Operational'' Penalties

a. Unreserved Use Penalties

NOPR Proposal

826. In the NOPR, the Commission proposed to clarify that unreserved use penalties apply to any circumstance where a transmission customer uses transmission service that it has not reserved.[508] Specifically, the transmission customer would be subject to an unreserved use penalty in circumstances where the transmission customer has a transmission service reservation, but uses transmission service in excess of its reserved capacity. A transmission customer also would be subject to an unreserved use penalty if the transmission customer uses transmission service where it does not have a transmission service reservation. The Commission also proposed that a transmission customer would not be subject to an unreserved use penalty in circumstances where the transmission customer inappropriately uses a network service reservation to support an off-system sale.

827. The Commission sought comment on whether the current policy that limits unreserved use penalties to twice the standard rate for the entire service period has resulted in penalties that are not just and reasonable and, if so, it sought further comment regarding provisions that would yield unreserved use penalties that are just and reasonable.

(1) Unreserved Use of Transmission Service

Comments

828. Several commenters express general support for the Commission's proposed clarification that unreserved use penalties apply to any circumstance where a transmission customer uses transmission service that it has not reserved.[509] Several commenters support the Commission's proposed clarification, but suggest that the transmission provider should only assess unreserved use penalties when a transmission customer repeatedly uses transmission service that it has not reserved.[510] For instance, PNM–TNMP believes penalty assessment should be optional and should be imposed on transmission customers that do not change their practices regarding transmission use and OATT compliance after being advised of their non-compliance.

829. Several commenters argue that transmission customers with special circumstances should not be subject to unreserved use penalties in the same manner as other transmission customers. For instance, Seattle believes unreserved use penalties can result in charges that are unjust and reasonable for intermittent resources, such as wind generators, that can not precisely schedule power in future periods, but are capable of controlling output. Seattle believes that unreserved use penalties should not apply if the transmission provider is able to operate the transmission system reliably. Seattle argues that an unreserved use penalty should only apply if scheduling parties have failed to respond to dispatchers' orders stating that system conditions necessitate curtailment of output. Southern disagrees with Seattle and states that, as a general principle, unreserved use penalties should not be based on whether reliability is threatened. TDU Systems recommend that the Commission consider treating inadvertent use of point-to-point transmission service in excess of reservations by an entity serving native load in multiple control areas as an energy imbalance in the control area in which the energy imbalance occurs, rather than an unreserved use of point-to-point service. In their reply comments, EEI and PNM–TNMP disagree with TDU Systems. EEI argues that energy imbalance charges compensate generators for the additional expense they incur to compensate for the customer's failure to schedule sufficient energy to serve its load and do not compensate the transmission provider for the use of the transmission system. EEI asserts that customers that use more transmission service than they schedule should be required to pay for that transmission service just like any other user of the system.

830. Duke opposes the Commission's proposed clarification and suggests that an effective means of deterring and punishing unreserved use of transmission service is to charge the customer for the point-to-point service necessary to support the transaction and, additionally, to make the customer subject to a civil penalty in cases of intentional or repeated unreserved use. TDU Systems argue on reply that a transmission provider should not be allowed to charge unreserved use penalties unless it employs software technology designed to identify unreserved use prior to operation.

831. Several commenters suggest modifications to the manner by which transmission providers determine when unreserved use penalties should be assessed. TDU Systems believes unreserved use penalties should only be applied with prior Commission approval after notice and opportunity for hearing in order to limit the transmission provider's discretion in applying such penalties. To encourage regulatory certainty, Seattle suggests that the Commission implement tariff provisions that state a clear basis for application of unreserved use penalties.

832. Several commenters ask that the Commission delete the proposed language added to section 30.4 of the proposed revised *pro forma* OATT regarding the unreserved use of a network resource beyond its designated capacity.[511] In the event the Commission elects to retain this language, these commenters ask the Commission to clarify the language to expressly permit use of the undesignated portion of a remote network resource under secondary non-firm service (as a non-network resource) and to preserve the customer's right to use the undesignated portion of the resource for other purposes (*e.g.*, to serve its load on systems other than the host transmission provider or to make off-system sales). In its reply comments, Duke notes that the fact that a generator is designated as a network resource for a network load on one system does not prohibit a network load on a second system from obtaining non-firm energy

[508] In the NOPR, we referred to an unreserved use penalty as an ''unauthorized use penalty.'' For the purpose of the Final Rule, we adopt the term ''unreserved use penalty'' as it more clearly articulates the nature of the penalty.

[509] *E.g.*, APPA and Bonneville.

[510] *E.g.*, MidAmerican, Southern, and PNM–TNMP.

[511] *E.g.*, APPA, TAPS, TDU Systems, and EEI Reply.

from that same generator using point-to-point and secondary network resource. Duke points out that the proposed revised section 30.4 prohibits a network customer from using its firm network service to schedule power in excess of the DNR amount. Finally, TAPS asks the Commission to modify the language added to section 30.4 so that its terms are consistent with the terms used in the rest of the *pro forma* OATT.

833. EEI recommends that a customer that takes unreserved transmission service, but that does not have a service agreement with the transmission provider, be deemed to have consented to the transmission provider's filing of a service agreement, so that the transmission provider has a basis for imposing both the prevailing OATT rate and the penalty charge on the customer. EEI also recommends that the Commission clarify that a customer that uses more transmission service than it has reserved also is subject to charges for ancillary services.

Commission Determination

834. The Commission adopts the NOPR proposal that a transmission customer will be subject to unreserved use penalties in any circumstance where the transmission customer uses transmission service that it has not reserved. Specifically, a transmission customer will be subject to an unreserved use penalty in circumstances where a transmission customer has a transmission service reservation, but uses transmission service in excess of its reserved capacity. A transmission customer also will be subject to an unreserved use penalty if the transmission customer uses transmission service where it does not have a transmission service reservation, including the situations described in the Arizona Public Service Company (APS) audit report.[512] We note that the transmission provider is subject to the same penalties when it takes transmission service under its OATT.

835. Our decision to clarify the application of unreserved use penalties will eliminate a potential source of discretion in the implementation of the *pro forma* OATT and will assist the Commission in its enforcement of the OATT obligations. The unreserved use penalty itself will help discourage disorderly use of transmission service. Charging a transmission customer for just the unreserved transmission service used, as suggested by Duke, would not provide a sufficient incentive to procure adequate transmission service, even with the threat of possible civil penalties. In addition, an operational penalty rather than a civil penalty is a more appropriate default remedy, even though certain circumstances may warrant a civil penalty in addition to an operational penalty. In most instances, an unreserved use penalty can be applied in a relatively mechanical manner. As a result, an operational penalty has a relatively low administrative burden and still provides a clear signal to transmission customers regarding the cost of non-compliance.[513] We do not agree with TDU Systems' proposal that a transmission provider be required to employ software designed to identify unreserved use if the transmission provider wants to charge unreserved use penalties. As we explain below, we adopt reforms in this Final Rule that will reduce the level of unreserved use penalties for instances of inadvertent unreserved use. For instance, we reduce the period over which a one-time inadvertent use will be penalized from one month to one day. We believe that this and other reforms are sufficient to address TDU Systems' concerns.

836. We will not adopt Seattle's suggestion to add provisions to the *pro forma* OATT that specify all circumstances that constitute use of transmission service without a transmission service reservation. Any list of transmission customer actions that would be deemed to constitute use of transmission service without a transmission service reservation will necessarily be incomplete and out-of-date given the dynamic manner by which trading patterns and practices evolve. We believe that Commission actions, such as in *APS*, will provide a sufficient guide to circumstances that constitute use of transmission system without a transmission service reservation. We also reject TDU Systems' suggestion that unreserved use penalties be applied only after Commission approval. As mentioned above, an unreserved use penalty can be assessed in a relatively straightforward manner in most cases. As a result, there will typically be little need for the Commission to become involved. That said, a transmission customer can always file a complaint with the Commission protesting an unreserved use penalty.

837. We will not exempt any class of transmission customer from the potential assessment of unreserved use penalties. We do not agree with Seattle's assertion that unreserved use penalties can result in charges that are unjust and reasonable for intermittent resources, such as wind generators, that can not precisely schedule power in future periods. Unreserved use penalties are based on the transmission capacity reserved rather than the transmission service scheduled, so an intermittent resource's inability to precisely schedule power in future periods is irrelevant, as long as the resource has reserved sufficient transmission capacity to deliver the resource's full output. We also do not agree with TDU Systems' suggestion that unreserved use of transmission service by an entity serving native load in multiple control areas should be treated as an energy imbalance in the control area in which the energy imbalance occurs, rather than an unreserved use of point-to-point service. In this regard, we agree with EEI that energy imbalance charges compensate the transmission provider for the additional expense it incurs to compensate for a transmission customer's failure to schedule sufficient energy to serve its load and do not compensate the transmission provider for the use of the transmission system.

838. We will not limit unreserved use penalties to instances where the unreserved use jeopardizes the reliable operation of the transmission system. Unreserved use penalties are intended, in part, to give transmission customers an incentive to reserve and pay for the appropriate level of transmission service so that transmission service is allocated in an orderly fashion. A transmission customer that uses unreserved transmission service requires the transmission provider to take some action to accommodate the additional use of the system. Some penalty is warranted even in those instances when the transmission provider's accommodations are sufficient to avoid curtailment of transmission service to other transmission customers. Absent a penalty in all instances, transmission customers would have an increased incentive to under-reserve transmission service, which would lead to an increase in the likelihood that system reliability would be impaired. In

[512] *Arizona Public Service Co.*, 109 FERC ¶ 61,271 at P 6 (2004) (*APS*). *APS* contained two findings that Commission audit staff characterized as unauthorized use of transmission service. In the first finding, APS's wholesale merchant function did not request and pay for point-to-point service to support some of the off-system power sales it made at trading hubs where APS system resources were directly connected. In the second finding, APS incorrectly treated the Phoenix Valley 230kV system as a single node on its transmission system. As a result, off-system sales made by generators connected to the Phoenix Valley system should have been, but were not, supported by point-to-point service.

[513] The unreserved use penalties thus work in conjunction with imbalance penalties described in section V.C.2 of this Final Rule to reduce incentives to take actions that impair the reliability of the transmission system.

addition, a transmission customer that uses more transmission service than it has reserved, even in periods when system reliability has not been impaired, has nonetheless disturbed the orderly allocation of transmission service.

839. In response to comments requesting that we remove the language added to section 30.4 of the proposed revised *pro forma* OATT regarding the unreserved use of a network resource beyond its designated capacity, we clarify our intent in modifying section 30.4. The Commission has identified instances when a transmission provider has scheduled delivery of off-system non-designated short-term purchases using transmission capacity reserved for designated network resources.[514] The intent of the language added to section 30.4 of the *pro forma* OATT was to clarify that network customers are subject to unreserved use penalties when they schedule delivery of off-system non-designated purchases using transmission capacity reserved for designated network resources. We clarify, however, that a network customer may use the undesignated portion of a remote network resource to serve network load using secondary network service and may use the undesignated portion of the resource for other non-network service purposes, such as third-party sales, as long as the network customer acquires the appropriate point-to-point transmission service. Moreover, because a transmission provider does not have to "take service" under its own OATT for the transmission of power that is purchased on behalf of bundled retail customers, it is free to use the undesignated portion of a remote network resource to serve its bundled retail customers.[515] If the transmission provider desires to use a remote network resource for non-native load purposes, such as third-party sales, it must acquire the appropriate point-to-point transmission service.[516]

840. In order to ensure that the transmission provider has a basis for charging an unreserved use penalty, we modify section 13.4 of the *pro forma* OATT to provide that a customer that takes unreserved point-to-point transmission service and does not have a service agreement with the transmission provider is deemed to have executed the transmission provider's form of service agreement for point-to-point service. In addition, we clarify that a customer that uses more transmission service than it has reserved is also subject to charges for ancillary services. The ancillary service charges will be based on just the period of unreserved use. For instance, if a transmission customer has unreserved use during two hours on the same day, the customer must pay the ancillary service charges for those two hours, rather than for the entire day. This modification is appropriate, as the transmission provider is entitled to compensation for the ancillary services it provides when it provides transmission service. We also will modify section 3 of the *pro forma* OATT to reflect this rule.

(2) Treatment of Inappropriate Use of Network Service as an Unreserved Use of Point-to-Point Transmission Service

Comments

841. A few commenters argue that a transmission customer that inappropriately uses a network service reservation to support an off-system sale should be subject to unreserved use penalties.[517] Other commenters request clarification or modifications to the Commission's proposal regarding the treatment of transmission customers that inappropriately use a network service reservation to support an off-system sale. TAPS asks the Commission to clarify that a transmission provider that inappropriately uses network service to support an off-system sale is required to pay for point-to-point service to support the off-system sale and potentially is liable for civil penalties, as the Commission proposed in the NOPR. Suez Energy NA suggests that an affiliate of the transmission provider that violates network tariff provisions by making unauthorized sales should also disgorge unjust profits from such sales. TDU Systems urges the Commission not to impose civil penalties for inadvertent use of network service by an LSE when it serves its own native load on a neighboring system.

Commission Determination

842. The Commission declines to adopt the NOPR proposal to exempt a network customer or transmission provider that inappropriately uses network transmission service to support off-system sales from unreserved use penalties. As mentioned above, one of the purposes of unreserved use penalties is to encourage orderly use and acquisition of transmission service. A network customer or transmission provider that inappropriately uses network transmission service to support off-system sales potentially uses or acquires transmission service that should be allocated to other transmission customers. In addition, the network customer or transmission provider has not paid for transmission service as required. Therefore, we conclude that a network customer or transmission provider inappropriately using network transmission service to support off-system sales should be subject to unreserved use penalties. We will evaluate the appropriateness of civil penalties in addition to unreserved use penalties on a case-by-case basis and will not exempt, as a matter of general policy, inadvertent use of network service by an LSE when it serves its own native load on a neighboring system as suggested by TDU Systems. A network customer or transmission provider that inappropriately uses network transmission service to support off-system sales also may be required to disgorge unjust profits from such sales, as the Commission may determine on a case-by-case basis.

(3) Penalty Rate for Unreserved Use of Transmission Service

Comments

843. Transmission providers generally assert that the Commission's current policy of limiting unreserved use penalties to twice the standard rate for the entire service period has yielded just and reasonable rates.[518] EEI contends that if the customer is required to pay an unreserved use charge only for the period of unreserved use, the customer would have an incentive to reserve service for less than its maximum expected use and simply pay unreserved use charges in the hours in which it exceeds that usage. EEI concedes, however, that the maximum period for which the unreserved use charge should be assessed is one month. For example, EEI acknowledges that it would be unreasonable to charge a customer that takes yearly service a penalty for an entire year because of, for instance, a single hour of unreserved use. In addition, EEI suggests several modifications to the current unreserved use penalty policy. EEI suggests the Commission include, in the *pro forma* OATT, provisions stating that the penalty charge for unreserved use of transmission service is equal to twice the standard rate for transmission service. EEI recommends that the Commission establish a policy that a

[514] *See MidAmerican Energy Co.*, 112 FERC ¶ 61,346 (2005); *PacifiCorp*, 118 FERC ¶ 61,026 (2007).

[515] *See* Order No. 888–A at 30,216–17.

[516] *See id.* at 30,217.

[517] *E.g.*, APPA and PNM–TNMP.

[518] *E.g.*, EEI, Bonneville, MidAmerican, Nevada Companies, and PNM–TNMP Reply.

customer that uses transmission service without a reservation must pay a penalty equal to twice the rate for transmission service for the greater of the period of unreserved use or one month.

844. Transmission customers generally assert that unreserved use penalties should be limited to twice the standard rate for the period of unreserved use.[519] Transmission customers who take this position argue that using the service period rather than the period of unreserved use as the basis for the penalty charge discriminates against transmission customers with longer term transmission service reservations.[520] For instance, AWEA believes that applying an unreserved use penalty based on the reservation period rather than the period of unreserved use has resulted in charges that are not just and reasonable. AWEA asserts that such a policy would also be discriminatory because, if the customer causing the unreserved use had made a shorter reservation, its penalty would be much lower. TDU Systems argue in its reply comments that there is little to be gained from charging inadvertent unreserved use more than twice the standard rate for the period of unreserved use.

845. Several commenters suggest that unreserved use penalty charges greater than twice the standard rate for the entire service period should be limited to instances of intentional unreserved use.[521] Nevada Companies note that there are some marketing entities that are consistently abusing the current policy and recommends that the Commission consider more severe penalties for continuous carelessness in tagging or a repeated pattern of unreserved use of the transmission system. Southern believes the transmission provider should be permitted to charge increased unreserved use penalties if a transmission customer consistently uses transmission services it has not reserved. TDU Systems disagree on reply comments, arguing that a penalty equal to twice the applicable charge is sufficient to deter unreserved use of transmission service.

Commission Determination

846. We will continue giving transmission providers discretion in setting their unreserved use penalty rates, although those rates will need to be consistent with this Final Rule. Penalty charges must be based on the period of unreserved use rather than the period for which service is reserved, subject to the following principles. First, the unreserved use penalty for a single hour of unreserved use will be based on the rate for daily firm point-to-point service, even if the transmission provider has a rate for hourly firm point-to-point transmission service on file. Second, as a general rule, more than one assessment for a given duration (*e.g.*, daily) will increase the penalty period to the next longest duration (*e.g.*, weekly). The unreserved penalty charge for multiple instances of unreserved use (*i.e.*, more than one hour) within a day will be based on the rate for daily firm point-to-point service. The unreserved penalty charge for multiple instances of unreserved use isolated to one calendar week would result in a penalty based on the charge for weekly firm point-to-point. The unreserved use penalty charge for multiple instances of unreserved use during more than one week during a calendar month will be based on the charge for monthly firm point-to-point.[522]

847. Our determination is based, in part, on agreement with those commenters arguing that using the period for which a transmission customer has reserved service rather than the period of unreserved use as the basis for the penalty charge discriminates against transmission customers with longer term transmission service reservations. We are mindful, however, that basing unreserved use penalties on only the period of unreserved use could give the transmission customer an incentive to reserve service for less than its maximum expected use and simply pay unreserved use charges in the hours in which it exceeds that usage. We believe the unreserved penalty regime we articulate in this Final Rule will provide a reasonable incentive to ensure that transmission customers reserve the appropriate level of transmission service without unduly charging a transmission customer for inadvertent unreserved use. In addition, transmission customers will continue to be subject to civil penalties on a case-by-case basis, so attempts to game this penalty regime could result in additional penalties depending on the specific facts at issue. We reject the suggestion in some comments that the transmission provider should only assess unreserved use penalties where a transmission customer repeatedly uses transmission service that it has not reserved. Rather, we find that penalties are appropriate for all unreserved uses of the system. Because we are allowing penalties to be based on the period of unreserved use, not the reservation period, such penalties do not unduly charge a transmission customer for inadvertent unreserved use. This penalty regime will apply to all instances where a transmission customer has an unreserved use of transmission service, regardless of whether the transmission customer had an existing relevant transmission service reservation but for a lesser amount of service.

848. A transmission provider that wants to charge unreserved use penalties must explicitly state the penalty rate in its tariff. The Commission retains the current policy established in *Allegheny* that the unreserved use penalty rate may not be greater than twice the firm point-to-point rate for the period of unreserved use, as defined above.[523] We continue to believe that penalties up to twice the relevant firm point-to-point rate are just and reasonable, given the new definition for the penalty period. As a result, we establish a rebuttable presumption that unreserved use penalties no greater than twice the firm point-to-point rate for the penalty period defined above are just and reasonable. As we discuss above, the transmission customer must face a penalty in excess of the firm point-to-point transmission service charge it avoids through unreserved use of transmission service or the transmission customer will have no incentive to reserve the appropriate amount of service.

849. The Commission thus concludes that a penalty of twice the standard rate is not excessively punitive, particularly given the definition of the penalty period established in this Final Rule. Without evidence to the contrary, we

[519] *E.g.*, APPA, AWEA, TAPS, and TDU Systems.

[520] *E.g.*, APPA, AWEA, TAPS, and TDU Systems Reply.

[521] *E.g.*, NRECA, Nevada Companies, and Southern.

[522] There are a number of possible permutations of these principles. For instance, a transmission customer that has 25 MW of unreserved use in two hours on one day during the first week of the month and 50 MW of unreserved use in two hours on one day during the last week of the month will pay an unreserved use penalty based on the rate for 25 MW of daily firm point-to-point service and 50 MW of daily firm point-to-point service. A transmission customer that has 25 MW of unreserved use on two separate days during the first week of the month and 50 MW of unreserved use in two hours on one day during the last week of the month will pay an unreserved use penalty based on the rate for 25 MW of weekly firm point-to-point service and 50 MW of daily firm point-to-point service. A transmission customer that has 25 MW of unreserved use on two separate days during the first week of the month and 50 MW of unreserved use on two separate days during the last week of the month will pay an unreserved use penalty on 50 MWs of monthly firm point-to-point service.

[523] *Allegheny Power System, Inc.*, 80 FERC ¶ 61,143 at 61,545–46 (1997) (Allegheny).

believe an unreserved use penalty equal to twice the applicable rate should create the appropriate incentive to transmission customers to purchase the correct amount of transmission service. Nonetheless, we will allow transmission providers to make a filing under section 205 of the FPA to propose an unreserved use penalty in excess of twice the relevant firm point-to-point rate for pervasive unreserved use. Transmission providers that propose such a rate must establish that a higher penalty rate is required to combat pervasive unreserved use of transmission. In arguing for such a higher penalty rate, the transmission provider must address why the standard penalty rate that penalizes repeated unreserved use is not adequate to discourage repeated instances of unreserved use of transmission service.

b. Distribution of Operational Penalties

NOPR Proposal

850. In the NOPR, the Commission proposed to have the transmission provider distribute to non-offending, unaffiliated transmission customers operational penalties incurred by the transmission provider's merchant function or its affiliates.[524] For those transmission providers subject to operational penalties, the Commission proposed to require the transmission provider to make an annual compliance filing to notify the Commission of the amounts of such operational penalties incurred during the year and to propose a method to identify non-offending, unaffiliated transmission customers to which the transmission provider would distribute penalty amounts. In addition, the Commission also proposed to allow a transmission provider to avoid an annual compliance filing by making a one-time filing to propose a mechanism through which it would identify non-offending, unaffiliated transmission customers and a method by which it would distribute the operational penalties it or its affiliates have incurred to the identified transmission customers. Finally, the Commission proposed to prohibit transmission providers from recovering for ratemaking purposes or through any service or facility under the Commission's jurisdiction any cost it incurs when it or an affiliate pays an operational penalty.

Comments

851. Transmission customers along with several other commenters support the Commission's proposal to distribute operational penalties paid by the transmission provider's merchant function to non-offending, unaffiliated transmission customers.[525] Entegra and Morgan Stanley advocate extending the proposal so that the transmission provider distributes operational penalties paid by all transmission customers to non-offending unaffiliated transmission customers. Entegra also notes that the Commission's policy in the natural gas setting is that pipelines must credit all penalty revenues back to non-offending shippers. Entegra argues that the precedent the Commission cited in proposing that operational penalties paid by the transmission provider be distributed to non-offending, unaffiliated transmission customers applies equally to penalties paid by affiliated and unaffiliated transmission customers.[526]

852. With regard to unreserved use penalties, NRECA and TDU Systems argue that the Commission should encourage transmission providers to supervise inadvertent unreserved use and notify the customer of such occurrence rather than rely on large unreserved use penalties. They argue it is better to prevent unnecessary costs than to approve *post hoc* penalties for unintentional unreserved use that could have been prevented.

853. A number of transmission providers oppose the portion of the Commission's proposal that would prohibit their non-offending affiliates from receiving a portion of the operational penalties the transmission provider incurs.[527] For instance, PNM–TNMP asserts that the Commission should allow the transmission provider's non-offending affiliates, which are abiding by the same rules as other transmission customers in accordance with Standards of Conduct, to be eligible to receive a portion of the operational penalties the transmission provider incurs. In the specific case of unreserved use penalties, Southern does not support distributing penalties imposed on a transmission provider's affiliate to other OATT customers. Southern argues that such a proposal is predicated upon the false assumption that such penalties are not of true financial consequence. Southern asserts that penalties paid by an affiliate do, in fact, represent a real cost to the wholesale business of that affiliated entity. In its reply comments, TDU Systems disagrees with comments that suggest that non-offending affiliates should be allowed to receive a load ratio share of penalty revenues when a transmission provider or one of its affiliates incurs an operational penalty. TDU Systems argue that allowing any member of the corporate family to retain any portion of the penalty revenues incurred by another member of the corporate family will dilute the incentive inherent in the Commission's proposal.

854. Seattle suggests that compliance monitoring and enforcement to ensure that the transmission provider appropriately assesses penalties to its affiliates will be as important as correctly accounting for and distributing the revenues from penalties collected from affiliates.

855. Most commenters were supportive of the Commission's proposal to have transmission providers notify the Commission of the amounts of all operational penalties they incurred during the year through either an annual compliance filing or a one-time filing.[528] Several commenters expressed a preference for a one-time filing by transmission providers.[529] For instance, Ameren states that it prefers the use of a one-time filing to propose a mechanism through which the transmission provider would identify non-offending, unaffiliated transmission customers and a method by which the transmission provider would distribute the operational penalties it or its affiliates have incurred to the identified transmission customers. Ameren believes this would be less burdensome than an annual repeated compliance filing. TDU Systems, on the other hand, prefer the Commission's proposal to require an annual reporting of penalties levied and penalty revenues credited in order to foster greater transparency on this matter. TDU Systems believe greater transparency through improved reporting requirements would provide greater opportunities for detecting abuses by transmission providers or their affiliates, either in imposing inappropriate penalties on transmission customers or in failing to penalize their own or their affiliates' transgressions. In addition, TDU Systems suggest that this reporting requirement should include details on the amount of penalties

[524] An operational penalty explicitly defines the charge associated with a set of pre-defined activities (*e.g.*, unreserved use of transmission service, completing request studies outside of the 60-day due diligence deadline) that are not in compliance with specific provisions of the OATT.

[525] *E.g.*, APPA, ELCON, Entegra, TAPS, TDU Systems, Sacramento, and Seattle.

[526] Entegra cites *Carolina Power & Light Co. and Florida Power Corp.*, 103 FERC 61,209 at P 24 (2003) (*Carolina Power & Light*).

[527] *E.g.*, EEI, MidAmerican, Nevada Companies, and PNM–TNMP.

[528] *E.g.*, EEI, Suez Energy NA, Sacramento, TAPS, and Wisconsin Electric.

[529] *E.g.*, Ameren and PNM–TNMP.

levied, whether on customers or the transmission provider or its affiliates, for all violations. With regard to the annual reporting requirements (for those companies that do not propose a standard mechanism to handle the distribution of penalties), Nevada Companies suggest that a standard template be proposed so that all companies are following the same reporting format.

856. Several commenters make recommendations that they argue will ease the administrative burden of distributing operational penalties paid by the transmission provider to non-offending, unaffiliated transmission customers. MidAmerican suggests that excluding short-term firm and non-firm transactions from the distribution methodology would avoid the need to develop a costly and administratively difficult program. TVA suggests that the amount of any such operational penalties should simply be a credit against the transmission provider's transmission revenue requirement, thereby more efficiently reducing the cost of transmission service to transmission customers.

857. Several commenters argue that the transmission provider must be made whole before it distributes any penalty revenues. For instance, EEI supports the Commission's proposal to the extent penalty revenues exceed the cost of transmission service. Nevada Companies assert that it is the transmission provider's native load that incurs the cost of correcting for the offending customer's intentional deviation from schedule or for a transmission customer's self-provided reserves being unavailable. Therefore, Nevada Companies contend that any penalties should be returned to the native load to offset its cost of generation.

858. Sacramento and WPS Companies' reply comments support the Commission's proposal to prohibit a transmission provider from recovering any cost it incurs when it or an affiliate pays an operational penalty through jurisdictional rates or services.

Commission Determination

859. The Commission agrees with those commenters recommending that we broaden the NOPR proposal, which required transmission providers to distribute to non-offending, unaffiliated transmission customers only the unreserved use penalties the transmission provider's merchant function incurs. Consistent with our conclusion regarding imbalance penalties, we conclude that it would be more appropriate for transmission providers to be required to distribute all unreserved use penalties they collect, whether from the transmission provider's merchant function or other transmission customers. The penalties the transmission provider pays for late studies are penalties that, by their nature, are fully distributed only to non-affiliated transmission customers. Requiring the transmission provider to distribute the unreserved use penalty charges that its merchant function incurs will ensure that the transmission provider faces a meaningful financial consequence when its merchant function incurs an operational penalty. Extending the NOPR proposal to all unreserved use penalty revenues the transmission provider collects maintains the incentive structure of the unreserved use penalty and prevents the transmission provider from retaining revenues above those it should reasonably be allowed to earn.[530] This determination is consistent with the Final Rule for imbalance penalties and the Commission's decision in Order Nos. 637 and 637–A.[531]

860. We agree with those commenters that suggest that non-offending affiliates of the transmission provider, including the transmission provider's native load customers, should be eligible to receive a portion of the unreserved use penalties that the transmission provider collects. Unreserved use penalties are assessed against transmission customers and should, therefore, be distributed to all non-offending transmission customers, whether affiliated with the transmission provider or not. Given the distribution of unreserved penalties articulated above, the transmission provider's corporate profit is reduced if one of the transmission provider's wholly-owned marketing affiliates pays an operational penalty to the transmission provider. This is so because the corporate shareholders ultimately pay the marketing affiliate's penalty, while the transmission provider distributes the revenues to non-offending transmission customers.

861. The Commission requires the transmission provider to make an annual compliance filing and to propose in that filing a mechanism through which it will identify non-offending, transmission customers and a method by which it will distribute the unreserved use penalties revenue it receives to the identified transmission customers. This rule is consistent with our determination regarding the distribution of imbalance penalties. The transmission provider must also indicate in its compliance filing how it will distribute late study penalties to unaffiliated transmission customers. In addition, the transmission provider is required to make an annual filing with the Commission, described further below, that provides information regarding the penalty revenue the transmission provider has received and distributed. We will not allow the transmission provider to make an annual filing to propose a distribution method for unreserved use and late study penalties, as proposed in the NOPR. We agree with Ameren that restricting the transmission provider to proposing a distribution method through the transmission provider's compliance filing will reduce the administrative burden of distributing operational penalties. We believe that we can accomplish the goals underlying a mandatory annual filing to propose a distribution method—to detect inappropriate penalties and failure to penalize the transmission provider's affiliates—by requiring an annual informational filing. As suggested by Seattle, compliance monitoring and enforcement by Commission staff will provide a measure of assurance that the transmission provider appropriately assesses penalties.

862. All point-to-point and network transmission customers, including the transmission provider's native load, will be eligible to receive a portion of the penalty revenues distributed by the transmission provider. As a result, we will not adopt MidAmerican's proposal that we exclude short-term firm and non-firm transmission customers to reduce the burden to the transmission provider. Given the steps we have taken to manage the transmission provider's burden of distributing penalty revenues, we believe it more equitable to allow all transmission customers subject to operational penalties to be eligible to receive a portion of the distributed penalty revenues. In response to TVA's suggestion that the amount of any such operational penalties be credited against

[530] As we explain further below, the transmission provider will be allowed to retain the base firm point-to-point transmission service charge when it assesses an unreserved use penalty.

[531] *Regulation of Short-Term Natural Gas Transportation Services, and Regulation of Interstate Natural Gas Transportation Services,* Order No. 637, 65 FR 10156 (Feb. 25, 2000), FERC Stats. & Regs. ¶ 31,091 at 31,309 (2000) (''* * *to effectively shift pipelines to the use of the non-penalty mechanisms described above to solve and prevent operational problems, it will be necessary to eliminate the pipelines' financial incentive to impose penalties and OFOs. Thus, the Commission is requiring pipelines to credit the revenues from penalties and OFOs to shippers.''); *order on reh'g,* Order No. 637–A, 65 FR 35706 (Jun. 5, 2000), FERC Stats. & Regs. ¶ 31,099 at 31,609 (2000) (''The goal of the Commission's new policy on penalties is to encourage pipelines to rely less on penalties and more on non-penalty mechanisms to manage their systems* * *.'').

the transmission provider's transmission revenue requirement, we note that the transmission provider is free to propose this mechanism, with assurances that offending customers will not benefit, and we will decide the appropriateness of the proposal on a case-by-case basis.

863. We agree with those commenters that assert that the transmission provider must be made whole before it distributes any penalty revenues. With regard to unreserved use penalties, we will allow the transmission provider to retain the base firm point-to-point transmission service charge, but require it to distribute any revenue collected above the base firm point-to-point transmission service charge. For instance, if a transmission customer has unreserved use that results in a penalty equal to twice the rate for firm weekly point-to-point service, then the transmission provider can retain an amount equal to the rate for firm weekly point-to-point transmissions service. A transmission provider will be required to distribute the entire amount it pays for completing service request studies on an untimely basis.

864. We will not require transmission providers that make an annual compliance filing to use a standard template, as suggested by Nevada Companies. Transmission providers are in the best position to determine the least burdensome way to present the information required. We will provide guidance, however, on the information that transmission providers must provide in their annual informational filings. Transmission providers must provide: (1) A summary of penalty revenue credits by transmission customer, (2) total penalty revenues collected from affiliates, (3) total penalty revenues collected from non-affiliates, (4) a description of the costs incurred as a result of the offending behavior, and (5) a summary of the portion of the unreserved penalty revenue retained by the transmission provider.

865. Transmission providers are prohibited from recovering for ratemaking purposes or through any service under the Commission's jurisdiction any amount it or an affiliate pays as an operational penalty. This will ensure that the transmission provider faces a true financial consequence when it or an affiliate incurs an operational penalty.

c. Applicability of Operational Penalties Proposal to RTOs and Other Independent or Non-Profit Entities

866. The Commission did not address the degree to which RTOs and other independent entities would be subject to operational penalties in section V.C.4 (Operational Penalties) of the NOPR. For the most part, the discussion in that section of the final rule addressed how a transmission provider should distribute operational penalties it incurs when it takes transmission service under its own tariff. In the section V.D.5 (Acquisition of Transmission Service) of the NOPR, the Commission separately addressed whether RTOs should pay operational penalties for failure to complete request studies on a timely basis.

Comments

867. Several RTOs and RTO members asked that the Commission clarify that RTOs are not subject to any operational penalties.[532] Entergy opposes the Commission's proposal to assess operational penalties against non-RTO transmission providers, but not RTOs. However, if the Commission maintains this distinction, Entergy asks that it clarify that independent entities—such as Entergy's Independent Coordinator of Transmission—and the transmission providers that allow independent entities to process transmission service requests will have the same protection from operational penalties as RTOs. PGP argues that, in the case of non-profit transmission providers, requiring the transmission provider to pay ''non-offending'' customers when the provider incurs operational penalties is self-defeating, because there is no one other than the customers to bear the cost of the penalty. PGP cites Bonneville as an example and notes that Bonneville must recover all costs from its customers.

Commission Determination

868. This section of the Final Rule primarily addresses how transmission providers should distribute operational penalties they incur when taking transmission service under their own tariff. RTOs and independent transmission coordinators do not take transmission service, so most of the discussion in this section of the Final Rule is simply not applicable to either RTOs or independent transmission coordinators. RTOs and independent transmission coordinators are bound however by the requirement to distribute revenues they receive when they assess operational penalties. We address whether RTOs or independent transmission coordinators are subject to operational penalties due to processing transmission service request studies on an untimely basis in section V.C.5.a of this Final Rule. We address whether RTOs are subject to civil penalties in section 0 of this Final Rule.

869. We do not agree with those arguing that a non-profit transmission provider should be exempt from the requirement to distribute unreserved use penalties it pays when taking service under its own tariff. To the extent that a not-for-profit transmission provider incurs an operational penalty as a result of its activities as a transmission customer, it is still required to distribute penalties to non-offending customers. A non-profit transmission provider would only incur an operational penalty as the result of its wholesale marketing operations. As such, a non-profit transmission provider would pay for any operational penalty it incurs by using the profit it has earned through its wholesale marketing operations.

6. ''Higher of'' Pricing Policy

870. As noted in the NOPR, the Commission is concerned that some transmission providers may not be applying our existing pricing policies consistently and, as a result, customers may be quoted prices that are not consistent with the ''higher of'' policy.[533] The practice of quoting customers an incremental rate as a lump sum payment is inconsistent with our ratemaking policy and has the potential to discourage customers from proceeding with service requests.[534] Under the Commission's ''higher of'' pricing policy, when the requested transmission service requires network upgrades, the transmission provider should calculate a monthly incremental cost transmission rate using the revenue requirement associated with the required upgrades and compare this to the monthly embedded cost transmission rate, including the expansion costs.[535] This incremental rate should be established by amortizing the cost of the upgrades over the life of the contract.[536]

[532] *E.g.,* ISO New England, PJM, MISO, SPP, and Ameren.

[533] In Order No. 888, the Commission stated that system expansions should be priced at the higher of the embedded cost rate (including the expansion costs) or the incremental cost rate, consistent with the Transmission Pricing Policy Statement. *See Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act,* Policy Statement, 59 FR 55031 at 55037 (Nov. 3, 1994), FERC Stats. & Regs. ¶ 31,005 at 31,146 (1994), *order on reconsideration,* 71 FERC ¶ 61,195 (1995) (Transmission Pricing Policy Statement).

[534] *Southwest Power Pool, Inc.,* 100 FERC ¶ 61,096 (2002) (designing a rate to include a balloon payment is not a substitute for a properly designed rate).

[535] *Southwest Power Pool, Inc.,* 112 FERC ¶ 61,319 at P 33 (2005).

[536] *See Southwest Power Pool, Inc.,* 98 FERC ¶ 61,256 at 62,026, *reh'g denied in pertinent part,*

NOPR Proposal

871. As a result of the Commission's concerns regarding application of the ''higher of'' pricing policy, the Commission sought comments in the NOPR on whether changes to the *pro forma* OATT are necessary to ensure that incremental cost transmission rates are presented as monthly rates for service.

Comments

872. Several commenters agree that incremental cost rates must be expressed as monthly rates, but do not believe that imposing this requirement requires changes to the *pro forma* OATT.[537] To ensure transparency, Bonneville recommends that transmission providers post on their OASIS the methodology used to calculate incremental rates. APPA suggests that the Commission simply state in the preamble to the Final Rule that the transmission provider must include a proposed incremental rate in its offer of service.

873. Other commenters see no need for clarification at this time. Southern states that it is not aware of problems regarding the calculation of incremental rates. Southern requests that the Commission consider allowing deviations to the Commission's ''higher of'' pricing policies and to allow all transmission providers, not just RTOs, to utilize participant funding. MidAmerican suggests the Commission defer consideration of possible changes to the *pro forma* OATT regarding this issue until the Commission undertakes comprehensive transmission pricing reform.

874. Other commenters support changes to the *pro forma* OATT that will ensure that incremental costs are presented as monthly rates for service.[538] EPSA suggests that the Final Rule include an example of an appropriate monthly revenue requirement calculation and the upgrade costs included in the monthly rate. Suez Energy NA supports this proposed change but requests that the transmission provider be required to provide in a clear format the existing transmission rate, the lump sum cost of the upgrades, and the incremental rate.

875. Some commenters ask the Commission to further clarify, or establish additional requirements, regarding incremental rates. Entegra states that the incremental rate should be stated as both a monthly unit rate and a lump sum representing the net present value of the upgrade costs with all inputs and assumptions in the calculation disclosed. Entegra further contends that the customer should be allowed to choose between paying the incremental rate, the lump sum, or some combination of the two (*e.g.*, to pay an incremental rate over some period of time and then to pay the balance of the upgrade costs as a lump sum). While Morgan Stanley supports the Commission's clarification that the transmission provider may not demand a lump sum payment as a condition of providing the requested service, it asks that transmission providers not be precluded from offering a lump sum payment option, or any other mutually agreeable approach, to customers.

876. MidAmerican, EEI and Allegheny recommend that the Commission clarify that the transmission provider is not currently limited to charging the customer the rate per MW-month specified in the facilities study for the entire term of service if the customer pays the incremental cost of the network upgrades. These commenters explain that the transmission provider's revenue requirement with respect to the incremental cost of network upgrades will vary over the customer's term of service in the same way as its embedded cost of service will vary, including the cost of capital, operations and maintenance expense and administrative and general expense. EEI argues that the transmission provider should have the same right to modify a rate based on incremental costs pursuant to section 205 that it has to modify embedded cost rates and that the transmission provider should be permitted to present an incremental cost rate as a formula rate.

877. Seattle states that incremental costs may require more rigorous treatment than simply stating a monthly rate, since the cost of expansion is very path specific and often the expansion will affect multiple beneficiaries. According to Seattle, the ''higher of'' pricing policy will often hinge on contestable assumptions regarding the beneficiaries of discrete expansion projects and the grey area that separates reliability related aspects of new transmission projects from projects intended to provide commercial benefits.

878. Great Northern requests that the Commission clarify that a transmission customer may adjust the term of its requested transmission service contract to provide a longer period for amortizing the cost of necessary system upgrades once the incremental cost of expansion is disclosed by the transmission provider, as the Commission seems to suggest in the NOPR.[539] In contrast, Allegheny states that the amortization period for the cost of an upgrade should not exceed the requested term of the contract, even if exercise of the rollover option by the customer is anticipated because transmission providers must have assurances of cost recovery for upgrades necessitated by customer decisions.

879. TAPS and EEI recommend that the Commission modify sections 19.3 and 19.4 of the *pro forma* OATT to specify that the transmission provider must present the incremental costs of transmission service on a $/MW month basis contemporaneous with providing the facilities study to the customer. TAPS further states that similar changes should be made to sections 32.3 and 32.4 of the *pro forma* OATT, to ensure that network customers are not scared off by inappropriate presentations of network upgrade costs. TAPS explains that, while more complex, it believes that ''higher of'' pricing can work in the context of network service if applied in a comparable manner to the transmission provider's treatment of the upgrades needed for service to its retail native load.[540]

880. ISO New England and PJM state that the Commission's pricing concerns are not present for their respective markets and, therefore, any rule promulgated in this proceeding should not apply to these RTOs.

881. TAPS argues that creditworthiness or security requirements associated with network upgrades for a transmission customer (in sections 19.4 and 32.4 of the *pro forma* OATT) must be distinguished from the incremental cost or pricing of the upgrade. Otherwise, the customer may mistake a demand for security for a request for upfront payment of the entire cost of the upgrade.

882. In reply comments, EEI states that it continues to support the Commission's proposed modification to the way in which the transmission

100 FERC ¶ 61,096 (2002) (''We agree with SPP that the amortization period for upgrade costs should match the contract period * * * As the customer is only obligated to take service for the term of the contract, it is reasonable that the costs only be amortized over the term of the contract.'').

[537] *E.g.,* APPA, Bonneville, and Public Power Council.

[538] *E.g.,* ELCON, Constellation, FirstEnergy, NorthWestern, PGP, TDU Systems.

[539] *See* NOPR at P 285 (''Presenting the incremental charge in the form of a monthly rate allows a customer seeking a lower rate to choose to request a longer transaction term.'').

[540] *Citing Midwest Indep. Transmission Sys. Operator, Inc.,* 109 FERC ¶ 61,085, P 57 (2004) (applying Order 2003 crediting mechanism to network customers).

provider presents information on the incremental cost of network upgrades and asserts that nothing in the initial comments justifies a change in the Commission's policies with respect to the pricing of transmission service. EEI states that changes in transmission pricing policy, such as NRECA's proposal to require rolled-in pricing for network customers and TAPS's proposal to exempt network customers from security for the payment of costs related to network upgrades, are outside the scope of this proceeding.

Commission Determination

883. In the NOPR, the Commission sought comments on the narrow issue of whether changes to the *pro forma* OATT are necessary to ensure that, consistent with our ''higher of'' policy, incremental cost transmission rates are presented as monthly rates for service. The Commission did not propose any changes to the underlying pricing policy. Commenters' proposals to change or clarify the Commission's transmission pricing policy are therefore outside the scope of this proceeding.[541] Other comments are directed toward the application of our ''higher of'' policy in individual cases. These include the comments of Seattle (on the need to accurately identify the beneficiaries of the network upgrades), TAPS (on the use of ''higher of'' pricing in the context of network service), and EPSA (asking the Commission to present an example calculation of costs and rates). We will not address those comments here because they involve issues that are largely fact-specific that are best addressed on a case-by-case basis.

884. Based on the remaining comments received, the Commission concludes that changes to the language of the *pro forma* OATT to address this matter are not needed at this time. We believe that the existing pricing policy provides sufficient information for transmission customers to make an informed decision regarding a request for service.[542] Transmission providers must continue to include a proposed monthly incremental rate with their offer of service whenever the transmission provider proposes to charge the customer an incremental rate, as well as cost support indicating the derivation of the rate calculation consistent with the cost support that the transmission provider would provide to the Commission in a section 205 rate filing. Because transmission providers are required to explain the calculation of their incremental rate, we conclude that the transmission provider need not post on its OASIS the calculation methodology, as recommended by Bonneville. Similarly, in response to TAPS's concern about security payments, the transmission provider's explanation should allow the customer to clearly distinguish between any security requirements associated with the service and the incremental cost of the service.

885. We will not adopt Great Northern's recommendation to require the transmission provider to permit the customer to opt for a longer contract term (to obtain a longer amortization period and a lower rate) once the incremental cost of the upgrades has been determined. The specific upgrades required to provide transmission service may depend on the time period over which the service is provided; therefore, allowing the customer to opt for a longer contract term may trigger a need for additional, or different, upgrades.

7. Other Ancillary Services

886. Other than the pricing of imbalances, the NOPR did not address pricing issues related to ancillary services required under the *pro forma* OATT. A few commenters nonetheless proposed revisions to the *pro forma* OATT regarding the pricing and procurement of, and other issues related to, ancillary services.

a. Demand Response

Comments

887. Alcoa submits that load resources (*i.e.*, demand response) should be permitted to self-supply and, under certain circumstances, sell ancillary services to third parties. Alcoa states that large customers such as aluminum smelters are capable of providing, for themselves and third parties, some ancillary services so long as they are not required to subrogate their aluminum business functions to the needs of the ancillary service markets. In Alcoa's view, demand resources such as Alcoa's smelter loads should be appropriately compensated as providers of ancillary services, recognizing their ability to contribute significantly to the operational flexibility of energy markets and the stability of the grid. Alcoa asserts that industrial loads' contribution to the reliability of the grid was demonstrated during the August 2003 Blackout, when Alcoa's smelters remained in operation and facilitated the restoration of the system. Accordingly, Alcoa asks the Commission to require transmission providers to recognize that demand response resources can be a substitute for ancillary services such as Energy Imbalance, Operating Reserve and Spinning Reserve.

Commission Determination

888. With respect to Alcoa's concern regarding a transmission customer's own use of ancillary service, we note that the existing *pro forma* OATT requires transmission providers to permit transmission customers to purchase ancillary services from third parties or make alternative comparable arrangements for the provision of all ancillary services except for scheduling, system control and dispatch service and reactive supply and voltage control service. Regarding the sale of other ancillary services including energy imbalance, operating reserve and spinning reserve by load resources, we agree that such sales should be permitted where appropriate on a comparable basis to service provided by generation resources. Comparable treatment of load resources is consistent with Staff's August 2006 Assessment of Demand Response & Advanced Metering Report[543] as well as provisions of EPAct 2005.[544] We note that some RTOs and ISOs already allow demand response resources to participate in certain ancillary services markets, while participation of such resources in other ancillary services markets is being studied. We therefore modify Schedules 2, 3, 4, 5, 6, and 9 of the *pro forma* OATT to indicate that Reactive Supply and Voltage Control, Regulation and Frequency Response, Energy Imbalance, Spinning Reserves, Supplemental Reserves and Generator Imbalance Services, respectively, may be provided by generating units as well

[541] Comments that fall into this category include those of Entegra, Suez Energy NA, Morgan Stanley, MidAmerican, EEI (regarding the right to modify incremental rates) and Allegheny.

[542] Because the Commission declines to adopt changes to the *pro forma* OATT regarding the ''higher of'' pricing policy, the requests of ISO New England and PJM to exempt ISOs and RTOs from tariff changes related to that policy are moot. Procedures regarding implementation of the Final Rule by ISOs and RTOs are otherwise discussed in section IV.C.

[543] In the Demand Response Report, staff recommended that federal and state regulators consider whether to allow appropriately designed demand response resources to provide all ancillary services including spinning reserve, regulation, and any new frequency responsive reserves. Demand Response Report at 97–100.

[544] Section 1252 (f) of EPAct 2005 states: ''It is the policy of the United States that time-based pricing and other forms of demand response, whereby electricity customers are provided with electricity price signals and the ability to benefit by responding to them, shall be encouraged, the deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy, capacity and ancillary service markets shall be eliminated.''

as other non-generation resources such as demand resources where appropriate.

b. Procurement and Pricing of Ancillary Services Generally

Comments

889. Steel Manufacturers Association contends that the *pro forma* OATT's approach to other generation-based ancillary services should recognize that regional ancillary services markets do a better job of ensuring system reliability and holding down ancillary services costs than ancillary services provided on a control area by control area basis. Steel Manufacturers Association cites to MISO and SPP reports that provide evidence that ancillary services provided across large geographical regions are more effective and economical than when those services are provided by single utilities. For example, Steel Manufacturers Association notes that the SPP report concluded that, if a single Area Control Error were used for SPP, energy used for regulation service could be reduced by approximately 30 percent. Steel Manufacturers Association contends that, although ancillary services markets in the organized markets have proven successful at ensuring reliability and at keeping ancillary services costs low and predictable, utilities outside of the RTO and ISO markets continue to provide ancillary services primarily from their own limited pools of generation resources.

890. Occidental and Steel Manufacturers Association propose that transmission providers should be required, if feasible, to competitively procure ancillary service products if there are suppliers of such services other than the vertically integrated merchant function. Occidental argues that such procurement will result in just and reasonable rates for these generation-related ancillary services that reflect their cost-effective market-based competitive supply. In Occidental's view, competitive procurement of ancillary services will also help assure non-discriminatory treatment of transmission customers since transmission providers will have less incentive to favor their merchant function in the provision of generation-related ancillary services. Occidental notes that such procurement should be conducted in a manner consistent with reliability.

891. Alcoa argues that the transmission provider's costs of providing ancillary services for the network as a whole should not be socialized on a MWh basis without regard to the relative cost burden that specific customers impose on the transmission system. Alcoa contends that, while a particular consumer may use a considerable quantity of energy, the cost of serving that customer beyond the per-unit energy cost may be much less than it would be for other individual customers or groups of customers.

Commission Determination

892. The Commission recognizes that there can be possible economic and reliability benefits to larger geographic markets for ancillary services, as suggested by Steel Manufacturers Association. However, as stated in the NOPR and repeated above the purpose of this rulemaking is to strengthen the *pro forma* OATT to ensure that it achieves its original purpose—remedying undue discrimination—not to create new market structures or, as proposed here, to modify existing market structures. We do not believe that altering the scope of the current ancillary services markets is needed to remedy undue discrimination at this time.

893. Similarly, we conclude that a fundamental overhaul of the current procurement and pricing of ancillary services, as proposed by Occidental and Steel Manufacturers Association, is beyond the scope of this proceeding.[545] The *pro forma* OATT already permits transmission customers to make alternative arrangements to satisfy certain of their ancillary services obligations. Therefore, transmission customers are free to seek out competitive providers for those ancillary services other than scheduling, system control and dispatch service and reactive supply and voltage control service from third party suppliers. We also find Alcoa's contention that the transmission provider's costs of providing ancillary services for the network as a whole should not be socialized on a MWh basis without regard to the relative cost burden that specific customers impose on the transmission system, to be beyond the scope of this Final Rule.

c. Pricing and Procurement of Reactive Power

Comments

894. Several commenters[546] suggest that the Commission consider the need for reform of the methods of compensation for the provision of reactive power.

895. Alcoa argues that ancillary services pricing should recognize the efficiency contributions made by load as a result of their demand response capabilities and the contribution that load located near generators makes to the provision of reactive power in particular. Alcoa states that the localized supply of reactive power near load centers can alleviate transmission constraints and allow cheaper real power to be delivered into a load center, as the provision of such reactive power increases the available flow for real power between two points. Alcoa argues that the *pro forma* OATT should recognize and credit the manner in which certain loads' location and load profile allows for the provision of reactive power and contributes to real power transfer capability.

896. Occidental objects to the existing requirement that transmission customers purchase reactive power service from the transmission provider, arguing that numerous independent generators provide reactive supply and voltage control to support transmission service in competitive wholesale markets. Occidental states that the Commission should formalize the policy of compensating generators on a comparable, non-discriminatory basis for several ancillary services, particularly providing reactive power capability, by requiring changes to the *pro forma* OATT to mirror the changes accepted by the Commission to the PJM and MISO tariffs. Occidental contends that amending the *pro forma* OATT to formalize this policy would be consistent with the FPA and achieving non-discriminatory access to transmission. Occidental notes that PJM and MISO amended their tariffs to provide equal compensation to affiliated and non-affiliated generators based on the generation owner's monthly revenue requirement for reactive supply and voltage control as accepted by the Commission. Occidental also notes that, when addressing generator interconnection agreements in Order No. 2003–A, the Commission stated that ''if the Transmission Provider pays its own or its affiliated generators for reactive power within the established [power factor] range, it must also pay [the interconnecting, independent generator].''[547]

897. SPP requests that the Commission reform its reactive power pricing methodology, which has grown

[545] We note, however, that the rates charged for these ancillary services must be just and reasonable under the Commissions standard of review. Thus, if less expensive options to supply ancillary services (including from demand side resources) are available, we would expect the transmission provider to examine such options.

[546] *E.g.*, SPP, Alcoa, and Occidental.

[547] *See* Order No. 2003–A at P 416.

out of *AEP Serv. Corp.*[548] SPP contends that the Commission can reduce uncertainty and litigation surrounding the pricing of reactive power by acting generically in a rulemaking rather than causing the industry to litigate reactive power pricing issues on a case-by-case basis. SPP argues that, based on its studies, it does not expect to call upon IPPs to provide reactive power; and therefore, it should not be required to pay for reactive power. SPP questions whether paying all IPPs a reservation charge, regardless of any determination of need or of the location of the plant and the locational need for reactive power, provides the appropriate siting incentives. SPP contends that the Commission can reduce the uncertainty and litigation by acting generically rather than causing the industry to fully litigate these issues in numerous cases before various courts. In addition, SPP challenges whether the AEP pricing method for reactive power continues to be appropriate. SPP suggests the Commission consider alternative pricing options, such as: Tying compensation to the actual provision of reactive power; eliminating compensation for the ninety-five percent leading/lagging band contained in most interconnection agreements, as such costs may be considered as a cost of interconnection and included in the power sales price; or, allowing compensation only outside of the band or perhaps when a sale is displaced.

Commission Determination

898. In Order No. 2003 *et al.*, the Commission found that interconnection customers must be treated comparably with the transmission provider and its affiliates in terms of reactive power compensation. The Commission required the transmission provider to pay interconnecting generators for providing reactive power within the specified range if the transmission provider so pays its own generators or those of its affiliates.[549] Commenters seeking reform of the methods of compensation for the provision of reactive power have not demonstrated that such reforms are needed at this time to remedy undue discrimination or that the current compensation method does not provide a comparable result. Accordingly, we do not believe that acting generically on pricing reactive power is needed at this time and we will continue to resolve compensation issues for reactive power to qualifying generators on a case-by-case basis based on the circumstances presented.

899. In response to SPP's specific proposals for the treatment of reactive power, we note that the Commission recently found that it is unduly discriminatory and non-comparable for SPP to apply a ''needs'' test to reactive power capability for independent power producers to receive compensation that is not also applied to all other generating plants in its vicinity.[550] The Commission also found that parties may make a separate FPA section 205 filing with the Commission with criteria, applied comparably and prospectively, that would determine which generators would receive reactive power compensation.

900. Finally, Alcoa's assertion that certain loads' location and load profile allows for the provision of reactive power to the transmission system is consistent with Staff's February 2005 report, Principles for Efficient and Reliable Reactive Power Supply and Consumption,[551] as well as the above-cited provisions of EPAct 2005. As previously discussed, we have modified Schedule 2 of the *pro forma* OATT to allow for the provision of Reactive Supply and Voltage Control from demand resources where appropriate.

D. Non-Rate Terms and Conditions

1. Modifications to Long-Term Firm Point-to-Point Service

a. Planning Redispatch and Conditional Firm Options

901. The current *pro forma* OATT requires the transmission provider to provide two types of redispatch service: Planning redispatch and reliability redispatch.[552] Planning redispatch is a product that Order No. 888 required transmission providers to use, in certain circumstances, to create additional transmission capacity to accommodate a request for firm transmission service. Specifically, the existing *pro forma* OATT requires the transmission provider to expand or upgrade its transmission system or, if it is more economical, plan to redispatch its resources to provide requested firm point-to-point service, provided redispatch does not (1) degrade or impair the reliability of service to native load customers, network customers and other transmission customers taking firm point-to-point service or (2) interfere with the transmission provider's ability to meet prior firm contractual commitments to others.[553] The transmission provider must first identify planning redispatch options in the system impact study in conjunction with identifying relevant system constraints that impact the service request.[554] When a system impact study and facilities study identify planning redispatch as a more economical means of relieving a transmission constraint than a transmission upgrade, the customer is obligated to pay the costs of redispatch consistent with Commission policy.

902. Reliability redispatch is required, when feasible, to relieve system constraints that would otherwise cause curtailment of the network customer or transmission provider loads. To provide reliability redispatch, the transmission provider redispatches all network resources and transmission provider resources on a least-cost basis. The transmission provider and network customers each pay a load ratio share of these redispatch costs.[555]

NOPR Proposal

903. In the NOPR, the Commission stated its belief that current practices for evaluating long-term firm point-to-point service may not be comparable to the manner in which transmission service is planned for bundled retail native load and may no longer be just, reasonable and not unduly discriminatory. The Commission described two potential solutions: modifications to the planning redispatch provisions and conditional firm point-to-point service.[556] The Commission proposed to modify the existing planning redispatch option by (1) accelerating the study of planning

[548] Opinion No. 440, 88 FERC ¶ 61,141 (1999).

[549] *See* Order No. 2003–B at P 119.

[550] *See Calpine Oneta Power, L.P.*, 116 FERC ¶ 61,282 (2006).

[551] *See* Staff Report: Principles of Efficient and Reliable Reactive Power Supply and Consumption (Docket No. AD05–1–000), available at *http://www.ferc.gov/EventCalendar/Files/20050310144430–02–04–05-reactive-power.pdf.* Staff noted that in many cases load response and load-side investment could reduce the need for reactive power capability in the system and that increasing reactive power at certain locations (usually near a load center) can sometimes alleviate transmission constraints and allow cheaper real power to be delivered into a load pocket. *See id.* at 4, 108. The report also noted that distributed generators have the same reactive power characteristics as large generators, with both producing dynamic reactive power, and that the amount of reactive power does not necessarily decrease when voltage decreases. *Id.* at 27.

[552] In Order No. 888, the Commission referred to planning redispatch as economic redispatch. Here we avoid the term economic redispatch because in the last ten years it has taken a different meaning in the industry and because we will no longer require that planning redispatch be capped at the cost of expansion.

[553] *See pro forma* OATT section 13.5.

[554] *See pro forma* OATT section 19.3.

[555] *See pro forma* OATT sections 33.2–33.3.

[556] Conditional firm point-to-point service (hereinafter conditional firm service) and planning redispatch point-to-point service (hereinafter planning redispatch service) are options available under long-term firm point-to-point service.

redispatch in the transmission request study process, (2) requiring an estimate of the number of hours of redispatch that may be required to accommodate the requested service, (3) requiring a preliminary estimate of the cost of planning redispatch, and (4) pricing planning redispatch services to facilitate increased availability of the service.[557] The Commission suggested that conditional firm service could also be used to accommodate additional transactions, defining the service as a form of firm point-to-point service that includes less-than-firm service in a defined number of hours of the year when firm point-to-point service is unavailable. The Commission sought comment on its preliminary view that planning redispatch is the superior option because, in part, it is comparable to the way the transmission provider plans for bundled retail native load.

904. The Commission's October 12 Technical Conference focused, among other things, on issues related to the planning redispatch and conditional firm proposals in the NOPR. On November 15, 2006, the Commission issued a notice (November 15 Notice) requesting supplemental comments on a transparent redispatch proposal submitted by Transparent Dispatch Advocates (TDA proposal) and certain aspects of the conditional firm option.[558] The Commission also requested comments regarding the conditional firm option, including whether it is a complementary service to planning redispatch, whether it should be available for all long-term requests or limited to a request where the customer agrees to pay for upgrades, potential modeling problems, and requirements for defining the conditions under which the service would be curtailable.[559]

Comments

905. Some commenters agree with the Commission's preference for modifications to planning redispatch over development of conditional firm service.[560] They state that the attributes of conditional firm service are not clearly defined and key implementation issues are unresolved. They state that using planning redispatch to the maximum degree feasible, while not interfering with reliability, is inherent in maximizing the efficient use of the transmission system and should be fully evaluated before undertaking expensive expansion of the transmission system. Other commenters state that conditional firm service will create significant complications for transmission providers and disincentives to build transmission in exchange for limited and questionable benefits for new point-to-point customers or LSEs.[561] EEI, Indianapolis Power and Ameren express doubt that customers would agree to be curtailed during peak usage periods. In response, AWEA contends that existing resources serving load would be able to manage curtailment risks so long as they could reasonably predict the curtailed hours.

906. Most independent power producers and a few other entities support the inclusion of both services in the *pro forma* OATT, stating that the services are required to remedy undue discrimination and provide for comparable transmission service.[562] Western Governors believe that the planning redispatch and conditional firm options are important to fully use the existing transmission grid and to enable new intermittent generation resources to reach markets. To build the case for transmission expansion, the Western Governors argue, it is important to demonstrate that the existing grid is being effectively utilized; approval of both options will help make this necessary demonstration. EPSA and AWEA state that, while they believe transmission providers should be required to offer both services, conditional firm service may be simpler and less costly to implement because it involves the transmission provider directing the customer to turn off its resources during a contingency. Similarly, Bonneville suggests that conditional firm service is a reasonable alternative to planning redispatch where a transmission provider cannot provide both options. Commenters state that the Commission should require transmission providers to offer conditional firm service and planning redispatch and allow customers to choose the option that best suits the physical, commercial and economic circumstances of the request.[563]

907. On the other hand, many commenters argue that the Commission should not require either option because the services are unnecessary, operationally unworkable, and legally unjustified, or because they would harm reliability and the quality of existing network service and provide disincentives for transmission investment.[564] Several commenters state that these services would make curtailments of existing firm service more likely and limit opportunities for use of secondary network service, thereby harming native load protections and reducing reliability, contrary to FPA sections 215 and 217 respectively.[565] Others opposing both options put forth primarily reliability, cost causation and comparability arguments. For example, Duke states that the two options are antithetical to reliable grid operation because they would require a transmission provider to grant a long-term request with the prior knowledge that it cannot be accommodated. International Transmission states that the grid is already operating at capacity and that requiring the transmission provider to accommodate additional megawatt-hours of service during periods of system stress would increase the likelihood of system failure. While it recognizes that conditional firm service has been successful in parts of the Western Interconnection, NRECA contends a mandate would undermine responsible planning and expansion of the transmission grid by harnessing the transmission provider's planning and dispatch functions to frame more and more elaborate service conditions for conditional firm service. APPA, Southern and Progress Energy argue that both services may require adoption of a form of organized LMP market, an action that raises significant political opposition and would be contrary to the Commission's commitment in the NOPR to avoid such restructuring. Similarly, other commenters contend that the planning redispatch option is only appropriate for transmission providers who are members of an RTO, ISO or

[557] The Commission did not propose to modify the reliability redispatch provisions that exist in the network integration transmission sections of the *pro forma* OATT.

[558] The following summary reflects comments received as initial and reply comments to the NOPR, as well as supplemental comments received in response to the November 15 Notice. Some commenters have changed their positions over time and these summaries reflect the most recent position expressed by commenters.

[559] Questions relating to the TDA proposal are discussed later in this section.

[560] *E.g.*, Exelon, FirstEnergy, ELCON, MidAmerican, Arkansas Commission, MISO, and East Texas Cooperatives.

[561] *E.g.*, EEI, Indianapolis Power, Ameren, and Northwest IOUs.

[562] *E.g.*, EPSA, AWEA, Entegra, BP Energy, Newmont Mining, Sempra Global, Suez Energy NA, PPM, Utah Municipals, Williams, Morgan Stanley, PPL, Project for Sustainable FERC Energy Policy, California Commission, CREPC, TranServ, South Carolina E&G, Constellation, Barrick Supplemental, Xcel Supplemental, and Bonneville Supplemental.

[563] *E.g.*, California Commission Supplemental, Williams Supplemental, Constellation Supplemental, and Barrick Supplemental.

[564] *E.g.*, Ameren, Duke, Entergy, Imperial, International Transmission, LPPC, Progress Energy, Santee Cooper, Salt River, Southern, Tacoma, TDU Systems, Community Power Alliance, Northwest IOUs, NorthWestern, NPPD, NRECA, Public Power Council, TVA, SPP Reply, South Carolina E&G Supplemental, E.ON Supplemental, MISO Supplemental, and APPA Supplemental.

[565] *E.g.*, Duke, EEI, LPPC, NRECA, NPPD, Progress Energy, Southern, Utah Municipals Reply, and Duke Reply.

who have an independent administrator of their transmission system.[566] Some of the commenters that urge rejection of both options state that a properly structured conditional firm service is preferable to the modified planning redispatch service should the Commission implement one of the services.[567]

908. Several commenters prefer the development of conditional firm service over the modifications to the planning redispatch service because of the complexities surrounding redispatch costs and protocols.[568] For example, in supplemental comments, EEI and Community Power Alliance state that, while not ideal, conditional firm service would provide an opportunity to meet customers' transmission needs and is preferable to Transparent Dispatch Advocates' redispatch proposal.[569] They also contend that the conditional firm option would provide faster provision of service and relative certainty of timing and costs for a new customer and its lenders, while ensuring reliability and promoting infrastructure expansion, so long as transmission providers are permitted to work with their customers to devise appropriate service parameters. Entergy believes conditional firm service can provide benefits to transmission customers without unfairly socializing costs to native load and network customers of the transmission provider. Overall, a majority of commenters express support for some form of conditional firm service.[570]

909. Several commenters argue that, if the services are required, the Commission should add to the services the following requirements: The services should not adversely affect reliability and service to firm customers or provide unduly preferential service to point-to-point customers; the services should be an interim option until transmission upgrades are in place to provide firm service; and, planning redispatch and conditional firm customers should bear the actual costs of the services received, including costs associated with system operational changes needed to accommodate the services.[571]

910. A few commenters believe that the Commission should allow for regional differences in development of the new services.[572]

Commission Determination

911. The Commission has determined that modifications to the current planning redispatch requirement and creation of a conditional firm option are both necessary for provision of reliable and non-discriminatory point-to-point transmission service. The planning redispatch and conditional firm options represent different ways of addressing similar problems. They can be used to remedy a system condition that occurs infrequently and prevents the granting of a long-term firm point-to-point service. These options also can be used to provide service until transmission upgrades are completed to provide fully firm service. Planning redispatch involves an *ex ante* determination of whether out-of-merit order generation resources can be used to maintain firm service. Conditional firm involves an *ex ante* determination of whether there are limited conditions or hours under which firm service can be curtailed to allow firm service to be provided in all other conditions or hours. As we explain below, both techniques are currently used under certain conditions by transmission providers to serve native load and, hence, it is necessary to make comparable services available to transmission customers in order to avoid undue discrimination.

912. We therefore find these options are complementary services that can remedy undue discrimination, facilitate the provision of long-term transmission service and provide customers with greater flexibility in choosing resources to meet their needs. There is support in the comments for development of some type of conditional firm service that would allow for a longer-term use of the grid when transmission is projected to be unavailable for a small portion of the year. Additionally, we note that both options could help integrate new generation more quickly. For example, when there is a lag between the time that a new generation resource becomes operational and the time that transmission upgrades can be built to accommodate the resource, these options allow power to reach customer loads at an earlier date. This can be particularly beneficial to renewable resources, such as wind, that can be constructed more quickly than the transmission upgrades necessary to deliver their power on a firm basis over the long-run.

913. We recognize, however, that both options raise reliability concerns. The proposal in the NOPR for planning redispatch service would require the transmission provider to predict system conditions for the term of the service request, a task that becomes more difficult, and hence less accurate, with longer-term requests. This poses several related problems. Because longer-term forecasts are inherently uncertain and the further into the future the forecasts, the less accurate they are, the provision of planning redispatch service can threaten the reliability of service to native load unless very conservative assumptions are used. This incentive to use conservative assumptions to protect native load, in turn, increases the likelihood that planning redispatch service will be denied. This, in turn, will increase the number of disputes as to whether the denials were discriminatory. Such disputes would pose enforcement problems because they will turn on long-term projections regarding load growth, generation resource additions, *etc.,* that by definition involve some degree of subjectivity. Moreover, as we discuss below, there is evidence suggesting that, while transmission providers use planning redispatch to serve native load, they do not use it as a long-term tool to avoid future upgrades indefinitely.

914. In balancing the foregoing considerations, the Commission will modify the approach proposed in the NOPR in two principal respects. First, given the ability of both services to address similar problems, we have reconsidered the proposal that only one of the options should be required. We find that availability of both planning redispatch and conditional firm in the short-run is necessary to ensure that competitive power suppliers have comparable access to the grid. As discussed below, we will continue to require that transmission providers offer to provide planning redispatch under certain circumstances in which the transmission providers determine that there is insufficient ATC. If customers

[566] *E.g.*, CREPC, TVA, and East Texas Cooperatives.

[567] *E.g.*, EEI, Entergy, Ameren, Progress Energy, Santee Cooper, TAPS, E.ON Supplemental, TDU Systems Supplemental, LPPC Supplemental, Tacoma Supplemental, and PNM–TNMP Supplemental.

[568] *E.g.*, Manitoba Hydro, Nevada Companies, Sacramento, Pinnacle, East Texas Cooperatives, Barrick Reply, APPA Supplemental, Community Power Alliance Supplemental, Entergy Supplemental, and TAPS Supplemental.

[569] Section V.D.1.b contains a summary and in-depth discussion of the TDA proposal.

[570] The following entities expressed some level of support for conditional firm service: EPSA, AWEA, Entegra, BP Energy, Newmont Mining, Sempra Global, Suez Energy NA, PPM, Utah Municipals, Williams, Morgan Stanley, PPL, Project for Sustainable FERC Energy Policy, California Commission, Western Governors, CREPC, TranServ, Constellation, Manitoba Hydro, Nevada Companies, Sacramento, Pinnacle, PNM–TNMP, Bonneville, EEI, Entergy, Ameren, Progress Energy, Southern, Santee Cooper, Seattle, LPPC, Salt River, and TAPS.

[571] *E.g.*, EEI, Southern, TAPS, Seattle, APPA, LPPC Supplemental, Tacoma Supplemental and E.ON Supplemental. Issues related to pricing of planning redispatch service are addressed in paragraphs V.D.1.a.3.c below.

[572] *E.g.*, California Commission, PGP, Pinnacle, and Imperial.

request study of planning redispatch, transmission providers have an obligation to seriously evaluate the provision of planning redispatch from their own resources and provide customers with information on the capabilities of other generators to provide planning redispatch. If planning redispatch is unavailable from the transmission provider's resources or inadequate to meet customers' needs, transmission providers have an independent obligation to offer conditional firm, if available, as part of the firm point-to-point service.[573] Customers will have the choice of whether to request study of the planning redispatch option, the conditional firm option or both.

915. Second, we will not impose a planning redispatch or conditional firm obligation over the long run. Such an obligation is not, as described below, necessary to remedy undue discrimination and would otherwise pose reliability problems, put the transmission provider at risk for estimating the costs of long-term redispatch, and undermine incentives to upgrade the transmission grid. Therefore, we will limit the availability of both service options so that their duration is for a time period over which service can be reasonably provided without impairing reliability.[574] This limitation scales back the existing planning redispatch requirement in section 13.5 of the *pro forma* OATT that could, in practice, allow for an open-ended obligation to provide planning redispatch in lieu of upgrading the transmission system (*e.g.*, involving forecasts up to 30 years).

916. We discuss in detail the comparability and reliability findings that support these decisions below.

(1) Comparability

NOPR Proposal

917. In the NOPR, the Commission expressed its preliminary view that current practices for evaluating long-term firm point-to-point service may not be comparable to the manner in which transmission service is planned for bundled retail native load and may no longer be just, reasonable and not unduly discriminatory.[575]

Comments

918. Some commenters challenge the Commission's authority to order planning redispatch or conditional firm service as a remedy for potential undue discrimination. EEI and others argue that planning redispatch is not necessary to eliminate actual or perceived undue discrimination because many transmission providers do not rely on redispatch in planning to serve native load.[576] However, EEI also states that when transmission providers do incorporate redispatch into their system planning, they do so generally only when the cost of redispatch is lower than the cost of network upgrades and system reliability is not impacted. Some transmission providers state that they do not currently use planning redispatch in lieu of transmission construction in order to designate their network resources.[577] On the other hand, Entergy and Southern state that they currently use or have used planning redispatch of their own resources on the same basis that they allow any network customer to redispatch from the network customer's resources. For example, Southern states that it has used the redispatch potential of its generators during off-peak/shoulder periods on an interim basis until completion of transmission upgrades to designate network resources that otherwise might be undeliverable.[578] Entergy disagrees that there is undue discrimination because this service is not available to point-to-point customers, stating that network and point-to-point service are not similarly situated services. TDU Systems state that conditional firm service does not ensure comparability among types of transmission service or between transmission providers and transmission customers. NRECA and others argue that the Commission requires a better understanding of the degree to which comparability is a problem in providing point-to-point service before the Commission makes changes to point-to-point service.[579] In supplemental comments, EEI contends that the record in this proceeding does not demonstrate that conditional firm service is necessary to remedy undue discrimination.

919. Others assert that it is not within the Commission's jurisdiction to order planning redispatch for point-to-point customers because this type of redispatch requires use of the transmission provider's generation resources.[580] LPPC states that the comparability principle is wrongly applied to the use of generation by a transmission provider. In Salt River's view, the Commission proposal sets up its own form of discrimination by making redispatch of the transmission provider's resources mandatory while making redispatch of generation using firm point-to-point reservations and generation in other control areas voluntary.

920. Those that support development of both services support the Commission's statement in the NOPR that ''transmission owners may evaluate transmission availability to serve long-term transmission service requests in a manner that is not comparable with the method they use to evaluate transmission needs for bundled retail native load.'' [581] They argue that this divergent treatment of internal transmission needs versus external transmission requests is unduly discriminatory and violates the FPA. EPSA states that the fact that point-to-point service requests can be rejected due to a few hours of predicted reliability problems in a year is ''evidence of a poor use of existing transmission capacity and display clear discrimination against non-affiliated generation and its customers.'' [582] TransAlta states that its actual experience with planning redispatch in the Pacific Northwest demonstrates that planning redispatch is used discriminatorily to the benefit of some customers and the detriment of others.

921. In support of conditional firm service, Manitoba Hydro and Tacoma reiterate their experience that long-term transmission service requests are being denied due to constraints occurring during a small percentage of the time within the requested period of service.

[573] Application of planning redispatch and conditional firm service obligations to RTO and ISO transmission providers is discussed in section V.D.1.a.3.B.i below.

[574] As explained in more detail below, we adopt limitations that are tailored to the two types of customers that may request the options. First, for customers that agree to support the construction of new transmission facilities, redispatch and conditional firm point-to-point service will be available as a bridge until such time as those facilities are constructed and the relevant conditions must be specified in the initial service agreement and are not subject to change. Second, for customers that do not agree to support the construction of new facilities, the transmission provider will be able to re-evaluate the conditions under which services are provided every two years.

[575] The Commission did not propose to modify the reliability redispatch provisions that exist in the network integration transmission sections of the *pro forma* OATT.

[576] *E.g.*, EEI, TDU Systems, NRECA, Southern, and Duke Reply.

[577] *E.g.*, Southern, Duke, and Progress. Duke suggests that the Commission exempt transmission providers from the obligation to provide redispatch if they commit not to use redispatch as a planning tool for native load, network customers or merchant functions.

[578] Southern states that it offered this service on a comparable basis to a non-affiliated transmission customer.

[579] *E.g.*, TDU Systems and EEI Reply.

[580] *E.g.*, LPPC, NPPD, Progress Energy, and Salt River.

[581] *E.g.*, AWEA, Utah Municipals, Project for Sustainable FERC Energy Policy, EPSA, and Barrick Reply *citing* NOPR at P 300.

[582] EPSA Reply.

EPSA and AWEA similarly state that a transmission provider will reject a long-term firm service request unless it can satisfy every element of the request. Manitoba Hydro and others state that, in an era of transmission under-investment, optimizing the capacity usage is paramount to system reliability.[583] EPSA and AWEA further explain that the concept of turning off a generator to avoid system upgrades is not new; Maine Independence Station avoided expensive system upgrades by installing automatic switching devices to take it offline during certain system conditions. Seattle states that, according to the Seams Steering Committee of the Western Interconnection, utilization on most constrained paths is limited to only a few hundred hours per year and, therefore, it is highly likely that service under a conditional firm product could be offered for even a baseload plant without significantly impacting the capacity factor. Santee Cooper states that, unlike the planning redispatch option, conditional firm service is presumptively within the subject matter jurisdiction of the Commission.

922. Entergy states that the most comparable service for long-term point-to-point transmission customers is not a requirement that a transmission provider redispatch its own or network customers' resources to grant long-term firm point-to-point transmission service. The most comparable service instead is a service that allows the transmission provider to curtail the service granted, while permitting the point-to-point customer to obtain alternative, deliverable resources if and when such curtailments occur in real-time.

Commission Determination

923. We reject arguments that planning redispatch service is unnecessary to remedy undue discrimination as a collateral attack on Order No. 888. The obligation to provide planning redispatch was established in Order No. 888. The modifications proposed in the NOPR did not increase the obligation placed on transmission providers to use their generation resources to provide planning redispatch to point-to-point customers. Rather, the proposed modifications merely added specificity to the redispatch information already required in a system impact study and adjusted the timing of when the transmission provider must study planning redispatch options.[584] Therefore, many of the arguments raised, including arguments pertaining to the Commission's jurisdiction over transmission provider generation resources, are impermissible collateral attacks on the current planning redispatch obligation in Order No. 888. Entergy's argument that planning redispatch should not be available to point-to-point customers because they are not similarly situated to be able to provide redispatch from their own units thus ignores the current obligation for each transmission provider to provide redispatch from the transmission provider's resources, if available, in evaluating a request for long-term point-to-point service.[585]

924. Additionally, information in the comments counters the assertion that transmission providers do not use planning redispatch or service analogous to the conditional firm option for their own loads. Entergy and Southern volunteer that they have planned for redispatch of their own resources in order to designate network resources when ATC was unavailable.[586] As a caveat, Southern states that it has planned for the use of redispatch only for an interim period until upgrades could be constructed to make the transmission service from the designated resource fully firm. Entergy states that it offers planning redispatch service to network customers that plan to use their own resources to provide redispatch in real time. Contrary to EEI's assertion about the record in this proceeding, commenters, such as EPSA and AWEA, explain that some transmission providers already employ automatic devices, such as special protection systems (SPS), to take resources offline during certain system conditions. In a way that is analogous to the proposed conditional firm service, these protection schemes are used to increase native loads' firm uses of the transmission system until a contingency occurs that reduces available transmission.[587] This information, taken together, provides ample evidence to support our finding that transmission providers currently evaluate transmission availability to serve long-term firm point-to-point transmission service requests in a manner that is not comparable with the method they use to evaluate their own transmission needs and to integrate their resources to serve bundled retail native load.

925. Furthermore, we wish to emphasize that, in making these findings in support of a conditional firm option, we are not relying on the findings to create a new service. This Final Rule retains the two services adopted in Order No. 888—point-to-point service and network service. Conditional firm service is not a third service, but rather represents a modification to the existing procedures for granting long-term point-to-point service and the curtailment priorities for that service. The primary purpose of conditional firm is to address the ''all or nothing'' problem associated with the current procedures for requesting long-term point-to-point service. Currently, a request can be denied because firm service is unavailable in a very few hours of the year. For a customer who needs long-term point-to-point service to support a long-term transaction, this leaves the customer in the position of trying to cobble together a collection of shorter-term requests to effectuate its transaction, *e.g.*, arranging firm service in the periods when it is available and non-firm service in the other periods. Such a customer also risks interruption of the non-firm portion of its service for economic reasons, *e.g.*, a day of non-firm service for the customer combining firm and non-firm service could be interrupted for another customer seeking one month of non-firm service. We do not believe such an approach is just and reasonable. It makes little sense to ask the customer to cobble together a collection of firm and non-firm requests when the transmission provider has better information about when the service may be available or unavailable. It is therefore appropriate to require the transmission provider to grant the service on a conditional basis, as we explain further below.

926. We are however modifying the planning redispatch obligation, and similarly limiting the conditional firm option, to better reflect the manner in which redispatch or special protections schemes are used by transmission providers, in recognition of certain legitimate reliability concerns and the inherent difficulty of long-term projections in this area. This Final Rule limits transmission providers' planning redispatch obligations by removing the current obligation to provide planning redispatch for an indefinite period as

[583] *E.g.*, EPSA, AWEA, and Project for Sustainable FERC Energy Policy.

[584] *See pro forma* OATT section 19.3.

[585] *See pro forma* OATT section 13.5.

[586] Entergy and Southern. EEI's comments also indicate that at least a few transmission providers do rely on redispatch in planning to serve their native loads.

[587] SPS, also known as remedial action schemes, are used to varying degrees in every NERC reliability region. For example, there are about 65 SPS in the Western Interconnection. *See Western Electricity Coordinating Council Operating Procedures*, Index, V–1 to V–5 (revised July 2, 2002). There are 8 SPS used by Florida Power and Light in FRCC. *See Florida Power and Light Control Area Readiness Audit Report*, 19 (March 10–11, 2004). Two SPS are used in the Southern Subregion of SERC. *Reliability Coordinator Readiness Audit Report Southern Subregion Reliability Coordinator*, 19 (March 27–30, 2006).

long as the redispatch is cheaper than the relevant transmission upgrades. We also limit the conditional firm option by linking it to the transmission upgrades or a biennial assessment of the conditions.

927. We find such an open-ended obligation to provide this service is not necessary to remedy undue discrimination, nor is it consistent with the need to maintain system reliability. As indicated above, transmission providers temporally limit their use of planning redispatch and curtailment of resources and there is no evidence that transmission providers use these options on a prolonged basis, *e.g.*, for more than a few years, without upgrading their transmission systems. Rather, over the long run, transmission providers generally will construct sufficient transmission to integrate their resources on a firm basis. This is consistent with transmission planning requirements and the emphasis placed upon transmission expansion in this Final Rule. The modifications to long-term point-to-point service we adopt are consistent and comparable to the existing use of these options by transmission providers' bundled retail native loads. Thus, the planning redispatch and conditional firm options will be available primarily as interim measures until transmission systems are upgraded to meet the transmission service request. We believe this limitation will have the added benefit of lessening disincentives to provide the service so that more planning redispatch is offered to transmission customers by transmission providers.

928. We disagree with TDU Systems' statement that conditional firm service does not ensure comparability among types of transmission service or between transmission providers and transmission customers. TDU Systems' assertion is unsupported by any explanation or examples of how the conditional firm service would degrade comparability. Nevertheless, we believe the argument is essentially a collateral attack on Order No. 888. Order No. 888, not this rulemaking, created the distinction between point-to-point transmission service and network integration service. We did so to recognize the different ways in which transmission providers typically use their system. The two services are not precisely the same, nor were they intend to be identical. Nothing in this Final Rule changes these distinctions. Indeed, we are not changing the relative priorities applicable to firm point-to-point service, network integration service and service to bundled native load.[588] These services do, and will continue to, share the same priority—the highest priority of firm service on the transmission provider's system. The only change, as it relates to the conditional firm option, is to allow the customer to elect to have its long-term firm transmission service interrupted under certain defined circumstances. This does not harm other firm customers. Indeed, it has precisely the opposite effect: it permits an interruption to maintain firm service to other customers. Moreover, we find, as indicated above, that conditional firm service is necessary to remedy undue discrimination.

929. The addition of conditional firm service therefore does not significantly alter the existing balance between the point-to-point and network service. Customers of network service retain flexibility that is not enjoyed by point-to-point customers. Moreover, conditional firm does not reduce the availability of secondary network service or the ability of network customers to temporarily undesignate network resources any more than short-term firm point-to-point service already reduces the availability of these network customer options. We therefore reject TDU Systems' arguments and find that the addition of conditional firm service is necessary to remedy undue discrimination and will otherwise increase utilization of the grid without impairing system reliability.

(2) Reliability

(A) Ability to Predict Redispatch Opportunities and System Conditions in the Long Run

Comments

930. Some commenters state that redispatch, used as a planning tool rather than as a short-term operational tool, is overly complex, prone to causing disputes, reduces reliability and thus should not be included in the *pro forma* OATT.[589] Southern asserts that planning redispatch should not be required where it reduces reliability by reducing a utility's reserve margin, shifting the operational, reliability and economic risks from the new customer to native load, or causing a single contingency to overload the system. Additionally, Xcel states that pledging a network resource to support planning redispatch carries a risk of penalties for inadequate resources in some areas. MISO states that contingency conditions must be considered and respected when evaluating planning redispatch options so that there is no reliance on curtailment of service. MidAmerican and Progress Energy conclude that the customer must accept the risk of selecting planning redispatch service over transmission construction.

931. Several commenters request modification of the existing planning redispatch provisions of the *pro forma* OATT.[590] They state that the Commission should clarify that the current section 13.5 does not require planning redispatch when it would adversely affect system reliability or service to native load, network customers and other firm point-to-point customers or impair other contractual obligations. Indianapolis Power states that the Commission should modify section 13.5 to require all reasonable redispatch options be examined by the transmission provider.

932. In its reply comments, Southern explains that transmission providers fail to provide the currently required planning redispatch service to point-to-point customers because the service is impractical and would harm reliability. Southern contends that a redispatch scenario identified in a transmission plan may not be available in real time due to outages or loop flow. Southern is also concerned about the complications in planning and modeling that would occur if the transmission provider is required to redispatch multiple resources in order to accommodate multiple planning redispatch customers.

933. Similar to their arguments in favor of conditional firm, EPSA and AWEA state that planning redispatch is necessary because a transmission provider will reject a long-term firm service request unless it can satisfy every element of the request, even if reliability violations occur in only a few hours of the year. In its reply comments, EEI responds that there is no evidence to support the assertion that a transmission provider will reject a long-term firm service request unless it can meet every element of that request. EEI states that in such a situation the transmission provider must offer partial service, offer to perform a system impact study, and exercise due diligence in constructing needed upgrades to accommodate the request. EEI adds that the potential customer can also request short-term service. Finally, EEI states that there is no evidence that transmission providers are refusing to redispatch in response to customer request when redispatching resources would have no impact on reliability. In

[588] *See supra* section V.D.5.b.

[589] *E.g.*, Duke, Entergy, WAPA, NRECA, NPPD, LPPC, and Southern.

[590] *E.g.*, EEI, Indianapolis Power, Public Power Council, Southern, Seattle, Sacramento, and LPPC.

its reply comments, MISO states that denial of service complained of by EPSA and AWEA is a consequence of the customer's economic decision not to build upgrades.

934. Many transmission providers assert that the costs and inequities of achieving the proposed planning redispatch outweigh any new benefits for point-to-point customers.[591] They state that the Commission's proposal is based on an erroneous assumption that redispatch is nearly always feasible; instead when redispatch is most desirable, generators operating at peak would not be available for redispatch.[592] Southern also explains that problems of insufficient transmission capacity cannot be avoided by redispatching generation because there is no guarantee that a redispatch solution will be available during real-time operations. Imperial argues that the personnel and modeling costs to transmission providers of calculating planning redispatch costs prior to a facilities study are too excessive. Xcel concludes from a NERC experiment on market redispatch that redispatch involving non-market-based or bilateral coordination with third parties to protect a delivery path is cumbersome, inefficient, and does not promote reliability.

935. Xcel states that its estimate of hours of planning redispatch is unlikely to be accurate given that it uses a static power flow that is created for a specific peak hour and a specific off-peak hour in a given year. Commenters state that planning redispatch service should not be a guaranteed service because generation or transmission availability, system loads, loop flows from adjoining systems, weather, and fuel availability all entail a component of risk that should not be pushed back on the transmission provider or its native load.[593]

936. Operators of systems that rely primarily on hydroelectric resources argue that planning redispatch should not be considered a viable option for their systems and they should be exempt from OATT planning redispatch obligations because hydroelectric operators are unable to make long-term commitments that a resource will be available to relieve transmission constraints.[594] Bonneville states that the variability in water flows and the interdependence of the generating units contribute to the inability to predict future redispatch ability. Bonneville, WAPA and Bureau of Reclamation state that planning redispatch can conflict with federal obligations to operate federal dams and reservoirs in a manner that does not impact project purposes and provide preference in the sale of hydropower to its preference customers. Tacoma states that planning redispatch must be linked to market price indexes to work in a hydro-based system. Seattle states that in hydro-dominant systems fuel availability and fuel price risk undermine the feasibility of providing long-run redispatch cost estimates that reasonably reflect future costs. Seattle adds on reply that planning redispatch fails to address costs pertaining to fish species preservation, recreation and flood control impacts, increased risk of spill, or replacement power that are associated with hydroelectricity.

937. Morgan Stanley argues on reply that the Commission should not exempt hydroelectric system operators from providing planning redispatch; instead, factors unique to hydroelectric systems should be taken into account in determining how much planning redispatch a transmission provider can provide. In supplemental comments, PPM agrees with Morgan Stanley and adds that hydro-based systems, such as Bonneville's, are flexible enough for a transmission provider to use planning redispatch to create additional firm capacity.

938. In their reply comments, Utah Municipals and EPSA state that planning redispatch would not impair reliability because the OATT provisions do not require transmission providers to permit intentional overloading of lines. Since transmission providers are already required to provide planning redispatch now, Utah Municipals contend that any change in the sequence for studying the option cannot have an impact on reliability. EPSA argues that claims of adverse reliability impacts should be dismissed because transmission providers do not make these same claims when they redispatch to enable transmission service to meet their own load obligations. Utah Municipals state that reliability would be most enhanced by completely restricting access to the grid, a policy that Utah Municipals do not recommend because it would be extraordinarily costly and promote discrimination. In its reply comments, Entegra states that customers seeking planning redispatch are not seeking to shift a disproportionate share of the risks or costs to native load or other users of the system.

939. In its reply comments, EPSA further argues that the Commission should place the burden of showing unreliability in a particular instance on the transmission provider. EPSA also argues that transmission providers should not be allowed to delay service through feasibility studies. EPSA contends that planning redispatch will not delay needed system upgrades and, instead, will ensure optimized use of the existing system that will provide additional information about the system's capabilities to regional planning initiatives. In its reply comments, Morgan Stanley states that the Commission should establish clear standards as to the degree of expected reliability that appends to a firm transmission sale and allow transmission providers to sell as much of the system as can be sold on a firm basis, consistent with maintaining the reasonable standard.

940. EEI and some transmission providers add that the conditional firm product could result in an oversubscription of a transmission system in violation of NERC reliability standards that require the transmission system to be planned to meet all firm needs.[595] ELCON states that conditional firm service may not truly support long-term contracts for firm power but may lead to a greater volume of short-term trading.

Commission Determination

941. Many commenters are concerned that the options described in the NOPR will impair system reliability. We have taken these comments into account and have tailored the modifications to long-term point-to-point service so as to not impair system reliability. There are two important limitations that provide such protections. First, we make clear that transmission providers are not required to offer planning redispatch or conditional firm service if doing so would impair system reliability.[596] Second, as explained above and discussed in further detail below, we are limiting the time period under which either option is offered. We do so because forecasts of potential redispatch or interruption options become more

[591] *E.g.*, Duke, Entergy, Imperial, International Transmission, Salt River, Seattle, Southern, Tacoma, Northwest IOUs, Sacramento, Progress Energy, E.ON, Xcel, TVA, and EEI Reply.

[592] *E.g.*, Sacramento and TVA.

[593] *E.g.*, Progress Energy, E.ON, WAPA, Entergy, and MidAmerican.

[594] *E.g.*, Bonneville, Seattle, Public Power Council, and WAPA.

[595] *E.g.*, Ameren, Southern, and EEI.

[596] A transmission provider may not be able to provide conditional firm service without impairing the reliability of its system if it is required, for example, to manage many conditional firm point-to-point reservations across the same path. The ability of system operators to track, tag and manage curtailment of multiple conditional firm reservations is necessarily limited by time, human resources and other reliability-related duties of the operators.

speculative over time and to require a transmission provider to commit for a substantial period of time, subject to the uncertainty inherent in such long-term projecting, has the potential to degrade reliability. With these two limiting conditions, we find that neither the planning redispatch nor conditional firm option will degrade reliability and, as discussed above, that both are necessary to remedy undue discrimination.

942. We agree with a majority of commenters that over the long term, new resources should be supported by sufficient transmission capacity to deliver their output reliably. Imposing a planning redispatch or conditional firm obligation over the long-run would not be consistent with the need to increase the reliability of the grid or otherwise necessary to remedy undue discrimination. Rather, it would tend to degrade reliability over time, contrary to the public interest and the underlying goals of EPAct 2005. Projections of planning redispatch options and conditional firm conditions are more accurate in the near term and, hence, should facilitate the efficient use of existing resources without impairing reliability.

943. We therefore impose limits on the transmission provider's current planning redispatch obligations. We do so by removing the obligation to provide planning redispatch for an indefinite period as long as the redispatch is less expensive than the relevant transmission upgrades. Section 13.5 of the *pro forma* OATT could, in conjunction with rollover rights, allow for an extremely long-term obligation to provide planning redispatch in lieu of upgrading the transmission system. We find that this existing obligation may unreasonably harm reliability and provides incorrect incentives to delay necessary grid expansion. We emphasize that the obligation to provide planning redispatch applies only when the service can be provided reliably.

944. We also limit the time period over which a transmission provider must predict the system conditions or conditional hours that would apply to customers using the conditional firm option. We do so in recognition of the difficulty in attempting to forecast curtailment options over the long-term and the fact that there is no evidence that transmission providers perform similar forecasts for their native load customers. We do not, however, eliminate entirely the risk of predicting future system conditions or shift it in whole to the requesting transmission customer as requested by certain commenters. We believe that the transmission provider should retain responsibility for incorporating reasonable assumptions into its transmission models so that it can manage this risk, just as it currently manages the prediction risk in its ATC models.

945. We will now turn to certain clarifications and other issues raised by the commenters. We acknowledge that planning redispatch to support annual service may require redispatch of generation during the peak month or months. Since transmission providers plan their generation to meet their peak native load plus reserves, the transmission provider's resources may, in some cases, be fully employed to meet the needs of bundled retail native load and thus may not be available to provide redispatch during the peak period.[597] In such an instance, the unavailability of such resources to provide redispatch service will constitute a legitimate basis for denying planning redispatch service. However, we will not excuse the existing obligation that requires transmission providers to study any available planning redispatch, including redispatch that might provide some but not all of the service requested. Given that some transmission providers have acknowledged their own use of planning redispatch for their network resources,[598] the service must continue to be available to those seeking point-to-point service to ensure comparability.

946. We reiterate that the transmission provider remains obligated to provide planning redispatch from its resources as long as the planning redispatch does not (1) degrade or impair the reliability of service to native load customers, network customers and other transmission customers taking firm point-to-point service or (2) interfere with the transmission provider's ability to meet prior firm contractual commitments to others.[599] We continue to believe these are the appropriate exceptions and will not adopt a broad and undefined reasonableness standard as suggested by Indianapolis Power. We agree with Southern that the transmission provider may consider the impact of the planning redispatch service in reducing its reserve margin below that necessary to maintain reliability or causing a single contingency to overload the system in determining whether the service can be reliably provided.

947. Further we will not excuse transmission providers from the obligation to manage multiple planning redispatch or conditional curtailment obligations simply because some commenters express concerns about planning and modeling impacts. While we do not take these concerns lightly, we believe they can be managed by transmission providers. The planning redispatch obligation has existed for ten years, and with it the potential for multiple planning redispatch requests. We have no evidence that transmission providers have been unable to manage the process. Moreover, by scaling back the time period for which transmission providers must plan for provision of redispatch, we have greatly reduced any planning and modeling impacts. We believe that whatever additional work the options cause with regard to planning and modeling, it is small and more than offset by the considerable value of the options which allow for more efficient use of the transmission system, expansion of long-term uses of the grid and remedying of undue discrimination.

948. Finally, we recognize the difficulty of predicting, over prolonged periods, whether hydroelectric resources will be available to provide redispatch. We agree with Morgan Stanley that factors unique to hydroelectric systems should be taken into account in determining how much planning redispatch a transmission provider can provide. For example, transmission providers operating hydro-based systems must predict both system load growth and water availability in order to determine whether resources will be available in the next few years to provide redispatch. We acknowledge that certain circumstances may in fact limit long-term redispatch on these systems due to increased prediction risks. We reiterate, however, that all transmission providers, including those operating hydro-based systems, are required to make a determination, regarding whether planning redispatch service can be provided consistent with system reliability based on the specific facts of a particular request for service. The fact that hydro-based systems may not be able to provide planning redispatch service under many circumstances should not necessarily limit the availability of conditional firm service on these systems. We expect that transmission providers with hydro-based systems will focus on provision of the conditional firm option in a manner consistent with their system conditions.

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[597] *See, e.g., Arizona Public Service Co.* v. *Idaho Power Co.*, 95 FERC ¶ 61,081 at 61,241 (2001) (resources projected to be unavailable during system peak month to provide planning redispatch).

[598] *E.g.*, Entergy.

[599] *See also* Order No. 888 at 31,739.

949. We also repeat that planning redispatch service does not need to be provided if doing so would impair the firmness of service to existing transmission customers. For example, pre-existing federal obligations, such as those described by Bonneville, WAPA and Bureau of Reclamation, would qualify as the type of firm commitments to others that would excuse transmission providers from the planning redispatch obligation to the extent that redispatch impaired service to these customers.

(B) Impact on Network Customers and Native Load

950. Several commenters argue that the use of planning redispatch may remove the ability to use reliability redispatch in real-time operations to respond to system contingencies, resulting in more curtailment of network and native load.[600] In addition to reducing availability of redispatch as an operational tool, NRECA contends that planning redispatch will reduce ATC for network service and the incentive to build new transmission. Several commenters state that planning redispatch may unfairly shift costs to network and native load customers.[601] Progress Energy argues that such a mandate places the power grid in serious jeopardy because the system has not been designed to handle the redispatch planning model. Progress Energy and Nevada Companies state that the planning redispatch option could conflict with transmission providers' state resource planning obligations to reliably serve load at least cost. Exelon replies, however, that planning redispatch could increase flexibility for network customers by increasing the availability of point-to-point service across adjacent transmission systems to bring generation to network loads.

951. Some commenters argue that the conditional firm option would adversely impact system reliability by subjecting firm customers to additional curtailments once conditional curtailment hours are exceeded.[602] NRECA and Utah Municipals state that the conditional firm service will reduce the flexibility of network customers by preventing network customers from using secondary network service, a right that NRECA argues is protected by FPA section 217.

Commission Determination

952. We reiterate that transmission providers are not required to offer planning redispatch and conditional firm point-to-point service if doing so would impair the reliable service to firm customers, including native load and network customers. The concerns of the commenters regarding the impacts on native load, network and other existing firm uses are therefore misplaced.

953. Transmission providers are already obligated to provide planning redispatch service pursuant to Order No. 888 and thus arguments that the planning redispatch option will harm existing customers is equally misplaced. Indeed, under the limitation on the duration of planning redispatch service imposed in this Final Rule, transmission providers will be able to better manage the risks of curtailment for current users of the transmission grid. This is because the obligation to redispatch will no longer be an open-ended obligation. Customers will need to commit to upgrade the system or to have their service reassessed periodically. Both of these allow the transmission provider to better plan to serve needs reliably because it reduces the unknowns. With regard to NRECA's argument that planning redispatch will cause less flexibility in real-time and more potential for curtailments of network customers and bundled retail native load, all sales of point-to-point service could to some extent cause more curtailments of network customers and bundled retail native load. Our decision today limits the existing planning redispatch obligation for point-to-point service, rather than expanding it.

954. Similarly, the conditional firm option does not reduce the availability of secondary network service or the ability of network customers to temporarily undesignate network resources any more than short-term firm point-to-point service already reduces the availability of these network customer options. We see no reason to reject the conditional firm option so that transmission providers avoid offering higher-quality service such as conditional firm point-to-point service in order to retain the ability to offer lower-quality service such as secondary network service.

955. Finally, we believe that network customers can benefit from the use of the planning redispatch and conditional firm options available in a point-to-point transmission service request. As described below, long-term point-to-point service that employs the planning redispatch or conditional firm option would qualify as a network resource on any adjoining system importing that resource.

(3) Implementation of Planning Redispatch and Conditional Firm Options

956. Commenters raise various concerns regarding specific implementation issues associated with the planning redispatch and conditional firm options. We address those concerns below, but first provide an overview of the planning redispatch and conditional firm service required in this Final Rule in order to outline the new rights and obligations of transmission providers and customers. Following this overview, we address specific comments relating to the service.

957. Pursuant to the modified obligations adopted in this Final Rule, where a request for long-term point-to-point firm transmission service is made and cannot be satisfied out of existing capacity, the transmission provider shall, at the request of the customer and in the system impact study, identify (1) the transmission upgrades necessary to provide the service, and (2) the options for providing service during the period prior to completion of those transmission upgrades. Additionally, if upgrades cannot be completed prior to expiration of the requested service term, the transmission provider shall, at the request of the customer and in the system impact study, identify options for providing the service during the requested term. The options studied by the transmission provider must include planning redispatch and conditional firm options.[603] The transmission provider, at its discretion, may study and offer a mix of planning redispatch and conditional firm options for a single service request. We provide further detail on each required option below.

958. If the transmission provider determines that planning redispatch is available, it shall provide the customer with non-binding estimates of the incremental costs of redispatch and identify the relevant constrained flowgates for which redispatch will be provided. For the conditional firm option, the transmission provider shall identify the conditions and hours pursuant to which the service may be curtailed, using a secondary network curtailment priority, to maintain reliability. Specifically, the transmission provider shall identify (1) the specific

[600] *E.g.*, EEI, Duke, Imperial, LPPC, PNM–TNMP, Public Power Council, NRECA, NPPD, Southern, and Progress Energy.

[601] *E.g.*, EEI, TAPS, LDWP, MidAmerican, Southern, Community Power Alliance, and MISO Reply.

[602] *E.g.*, Duke, LPPC, NRECA, NPPD, Progress Energy, Southern, APPA, and South Carolina E&G.

[603] Although partial interim service is not addressed in this rulemaking, we note that the OATT continues to require this service, on an as available basis, if a multi-year service request is denied.

system condition(s) when conditional curtailment may apply and (2) the annual number of hours when conditional curtailment may apply. Customers agreeing to take conditional firm service must choose one of these options, conditions or hours.

959. Where the customer requests firm service for more than two years, but is unwilling to commit to a facilities study or the payment of network upgrade costs, the transmission provider shall identify and provide the planning redispatch or conditional firm options subject to the following limitation. The transmission provider shall have a periodic right to reassess (1) the planning redispatch required to keep the service firm or (2) the conditions or hours under which the transmission provider may conditionally curtail the service. This reassessment may occur every two years during the term of the service, *i.e.*, at the end of year two, year four, year six, and year eight of a ten-year service. The transmission provider may not implement reassessments during intervening periods nor may it reassess the conditions in order to amend the service agreement in an intervening year should it forego any biennial reassessment.[604]

960. The service agreement shall specify the relevant congested transmission facilities and whether the transmission provider will provide planning redispatch, a mix of planning redispatch and conditional firm, or conditional firm in order to provide the point-to-point transmission service. For the conditional firm option, customers must choose among and the service agreement must specify either (1) specific system condition(s) during which conditional curtailment may occur or (2) annual number of conditional curtailment hours during which conditional curtailment may occur. We deem that any service agreement that incorporates planning redispatch or conditional firm options is a non-conforming agreement and must be filed by the transmission provider pursuant to section 205 of the FPA. Additionally, transmission providers must file with the Commission any amendments to these service agreements that result from reassessments. If a transmission provider proposes to change the redispatch or conditional curtailment conditions due to a reassessment, the transmission provider must provide the reassessment study to the customer along with a narrative statement describing the study and reasons for changes to the curtailment conditions or redispatch requirements no later than 90 days prior to the date for imposition of these new conditions or requirements. The transmission provider shall assess the conditions based on two years of service or the continuation of the term of service, whichever is less.

961. In situations in which the customer commits to paying the costs associated with upgrades necessary to provide the service on a fully firm basis, the conditions or hours identified by the transmission provider shall remain in effect until such time as the upgrades have been completed. Also, for such customers, the service agreement shall specify the upgrade costs as determined through the facilities study.

(A) Eligibility for and Timing of Planning Redispatch and Conditional Firm Options

NOPR Proposal

962. In the NOPR, the Commission proposed that customers who request long-term firm point-to-point transmission service and have the service denied because of lack of ATC would be eligible to receive planning redispatch service or, if the Commission chose to adopt the conditional firm service option, conditional firm service. The Commission also proposed earlier evaluation of the planning redispatch option in the system impact study rather than in the facilities study. The Commission proposed that, if it were to adopt conditional firm service, the evaluation of conditional firm availability should occur prior to a system impact study or facilities study.

Comments

963. If the conditional firm option is required by the Commission, many commenters believe it should be a bridge product to span the gap between when the relevant transmission service request is being studied and when the relevant upgrades become operational.[605] These commenters state that a bridge product is appropriate because it would not depress funding for new transmission infrastructure and would better meet the NOPR's and Congress' grid expansion objectives. In their view, use of a bridge product would avoid equity and free rider problems that may occur if a conditional firm customer is taking long-term service and the transmission system is upgraded during that service. They also argue that the bridge product would better allow for transmission providers to judge the likelihood of curtailment and avoid complicated system modeling and planning issues; as well as protect existing long-term transmission customers. Duke and Ameren state that an annual re-determination of the conditional period is necessary for a bridge product. If the upgrade has not been completed within a three year period, NRECA suggests that the customer be required to make a new long-term firm service request so the provider can update to reflect system conditions at that time.

964. Several commenters suggest that transmission providers should offer conditional firm service as both a bridge product and as a stand-alone long-term firm service.[606] Where not used as a bridge service, several commenters state that it should be limited to reservations that do not have rollover rights.[607] Duke argues that the service duration for non-bridge service should be one year, but with renewal rights that give the conditional firm customer a priority over other non-bridge conditional firm service customers seeking capacity. APPA supports one to two-year service offers.

965. In supplemental comments, EEI supports a voluntary conditional firm product with three types of service: A one-year product with no rollover rights; a bridge product for a term of more than one year that is provided until upgrades necessary to accommodate a firm service request are completed; and a non-bridge product of more than one year, with no rollover rights or transmission provider obligation to construct upgrades and subject to the transmission provider's periodic review of its system capability to provide such service. EEI contends that the Commission should encourage transmission providers to offer conditional firm service for more than one year without rollover rights to a customer that is not willing to take service of sufficient length to allow recovery of upgrades costs, if such service can be provided without affecting the reliability and quality of service to firm transmission customers.

966. In support of limitations on the term of conditional firm service, many

[604] For example, if a transmission provider opts to forego the reassessment at the end of year two, the transmission provider may not reassess the conditions of the service again until the end of year four of service for imposition of new conditions starting in year five.

[605] *E.g.*, Progress Energy Supplemental, PNM-TNMP Supplemental, LPPC Supplemental, APPA Supplemental, TAPS Supplemental, TDU Systems Supplemental, NRECA Supplemental, EEI Supplemental, Entergy Supplemental, Ameren Supplemental, Powerex Supplemental, and MISO Supplemental.

[606] *E.g.*, Bonneville Supplemental, PPL Supplemental, EPSA and AWEA Supplemental, EEI Supplemental, Barrick Supplemental, and Constellation Supplemental.

[607] *E.g.*, Xcel Supplemental, Duke Supplemental, and EEI Supplemental.

commenters state that analyzing and modeling system conditions will always be more accurate in the near term than in the long term.[608] EEI and Community Power Alliance believe that limitations on system modeling prevent many transmission providers from accurately evaluating their ability to provide conditional firm service over long periods. According to EEI, system conditions change on both the transmission provider's and neighboring systems substantially affecting the ability of the transmission provider to provide conditional firm service and the periods such service is subject to curtailment. While system loads can be predicted with a reasonable degree of accuracy for more than one year, other components of the prediction model, such as transmission and generator outages, typically are not determined more than a year in advance. For example, EEI states that members in the SERC region coordinate transmission and generation outages in a 13-month planning horizon. Duke states that the ability to model the system varies significantly by region. Entergy and MidAmerican believe that system modeling limitations would present serious reliability problems if transmission providers were required to offer a multi-year conditional firm transmission product because even the most advanced modeling software cannot predict long-term conditions that may affect service. Entergy and MidAmerican propose that the Commission allow transmission providers to update the curtailment criteria for a reservation, to reflect, among other things, changing load assumptions and forecasts over time. MidAmerican argues that without annual reevaluation there would be cost shifts to other firm customers. In its reply comments, MidAmerican explains that this reevaluation can only occur when the actual data becomes available for projecting potential curtailment hours.

967. If a transmission provider offers conditional firm service based on specified system conditions, Bonneville states in supplemental comments that limitations on modeling do not present a problem. If, however, the service is based on a maximum number of conditional curtailment hours per year, Bonneville believes that modeling presents problems in offering longer-term service. Bonneville states that forecasting the number of hours of conditional firm service requires great analysis. To remedy this, Bonneville suggests allowing the transmission provider to make conditional firm offers under which the transmission provider could periodically adjust the number of conditional curtailment hours.

968. In supplemental comments, Constellation proposes that the Commission require transmission providers to offer two types of conditional firm service: service for less than the service term eligible for rollover rights (*e.g.*, five years) if customers do not agree to pay for transmission upgrades; and service for five years or longer with a rebuttable presumption that the customer is obligated to pay for upgrades that are both economic and necessary to relieve the constraint that prevents its service from being fully firm.[609] EPSA and AWEA maintain that it is critical that the conditions be defined, and remain unchanged, for the term of the service agreement in order to obtain financing of new projects. EPSA and AWEA also propose that, if the contingency is removed during the life of the customer's conditional firm service, the service should convert to traditional firm service. Williams, EPSA and AWEA argue that up-front commitment to continue the conditions for the entirety of a long-term service agreement would take no greater risk than transmission providers take today in committing to other long-term firm transmission service. EPSA and AWEA state that limited term conditional firm service should pose no problems based on system modeling.

969. Several commenters believe that there is no need for any type of special rules for conditional firm customers taking bridge service and required to pay extremely expensive upgrades.[610] If the Commission abandons the ''higher of'' pricing principle for upgrades, these commenters suggest that any new pricing policies should be consistent with cost-causation principles and not result in any improper socialization.[611] Other commenters argue for special rules when upgrades are extremely expensive.[612] Xcel states that customers should have the option to take short-term conditional firm service that would remain subject to limitation and curtailment if upgrades are too expensive. Constellation proposes that customers taking the longer-term service should have the opportunity to show that upgrades would not be just and reasonable given the relevant circumstances, *e.g.*, the cost of upgrades for a single service request is $300 million. If the Commission determines that the bridge requirement in a particular circumstance is unjust and unreasonable, Constellation proposes that the transmission provider would provide the service for the requested term, but there would be no obligation for the transmission customer to pay for such upgrades, and the service would not be eligible for rollover. NRECA contends that instances in which special rules apply should be extremely rare and are best addressed by the transmission provider and customers on an *ad hoc* basis.

970. Commenters recognize that upgrades required under a bridge conditional firm option could create lumpiness problems,[613] but most commenters suggest that this problem is not unique to the conditional firm option, nor can it be resolved through use of the option.[614] These commenters support continuation of the Commission's existing policies with regard to lumpiness issues, and some suggest the need to address the issue as it pertains to all upgrades in a future proceeding.[615] In contrast, a few commenters suggest that the Commission should address the lumpiness issue with regard to conditional firm service. PPL, EPSA and AWEA state that the transmission provider should be required to pay the costs of any incremental lumpiness associated with upgrades and the service request. BP Energy contends that any lumpy capacity needs to be resolved on a bilateral contractual basis. Powerex suggests using an ''open season'' process to finance expensive and lumpy upgrades. California Commission supports prorating large lumpy

[608] *E.g.*, Nevada Companies Supplemental, TDU Systems Supplemental, LPPC Supplemental, Ameren Supplemental, Community Power Alliance Supplemental, MISO Supplemental, PNM-TNMP Supplemental, NRECA Supplemental, and Xcel Supplemental.

[609] EPSA and AWEA endorse Constellation's approach in defining and delineating the two forms of conditional firm service.

[610] *E.g.*, Nevada Companies Supplemental, Duke Supplemental, Bonneville Supplemental, Powerex Supplemental, BP Energy Supplemental, MISO Supplemental, PNM–TNMP Supplemental, Entergy Supplemental, Community Power Alliance Supplemental, and Southern Supplemental.

[611] Proposals regarding the ''higher of'' pricing policy are discussed below.

[612] *E.g.*, Xcel Supplemental, Constellation Supplemental, and NRECA Supplemental.

[613] In the November 15 Notice, the Commission described an example of lumpy capacity as upgrades to provide a requested 100 MW of point-to-point service that results in 1,000 MW of additional transmission capacity.

[614] *E.g.*, EEI Supplemental, Xcel Supplemental, APPA Supplemental, Bonneville Supplemental, LPPC Supplemental, NRECA Supplemental, Progress Energy Supplemental, Duke Supplemental, Ameren Supplemental, Entergy Supplemental, Community Power Alliance Supplemental, MISO Supplemental, Williams Supplemental, and PNM-TNMP Supplemental.

[615] *E.g.*, LPPC Supplemental, Bonneville Supplemental, and EEI Supplemental.

upgrades over a large base of new customers, to the extent that it is non-discriminatory and fiscally sound.

971. In supplemental comments, Nevada Companies urge that the time period of a conditional firm bridge product should be left up to the discretion of each transmission provider. They suggest that most, if not all, transmission providers should be able to offer a conditional firm service for a one-year period and most should be able to offer it for longer periods. Nevada Companies state that they should be able to provide conditional firm service in their control areas for longer periods, possibly for up to five years in some circumstances and in certain locations.

972. BP Energy and Williams disagree that conditional firm service should be a bridge product. They state that such a limitation would provide additional opportunities for undue discrimination and limit competitive alternatives used to serve customer load. According to California Commission, conditional firm service needs to be available for long-term requests unless there exists a valid, proven reason why conditions make it physically or economically impossible to guarantee such service. California Commission states that some limitations on modeling should be accepted as justification for not providing conditional firm or related services only if such provisions for load growth are nondiscriminatory, justified and contractually sound.

973. Commenters take both sides on whether planning redispatch should be evaluated before the customer is obligated to incur the costs and delays of a facilities study. EPSA argues that evaluation prior to a facility study meets nondiscrimination requirements given the methods used by transmission owners to evaluate planning redispatch for their own needs. In its reply comments, Exelon supports the minor changes to planning redispatch proposed by the Commission, including the earlier study of planning redispatch options in the system impact study, and states that these changes will expand choices for customers. EEI states that requiring an offer of planning redispatch prior to completion of a facilities study would be unduly preferential to point-to-point customers because transmission providers consider the costs of network upgrades and the impacts on system reliability before choosing planning redispatch for their native load. Southern points to the internal inconsistencies of the NOPR that on one hand seek to expedite the study process and on the other hand would require a planning redispatch study provision that would slow the study process.

974. EEI states that the vast majority of facilities studies show that the embedded cost of transmission service is higher than the incremental amortized cost of upgrades. Thus, EEI argues that the Commission's proposal to reform planning redispatch could lead to uneconomic decisions by the customer as well as provide disincentives to upgrade and expand transmission infrastructure.[616] In their reply comments, Utah Municipals respond that most of the time the embedded cost of transmission is higher than the costs of upgrades, adding that customers find requests for a transmission upgrades to be a time consuming and costly impediment to transmission access. Further, Utah Municipals add that limited and occasional redispatch or curtailment, would be more economically efficient than the construction of transmission facilities most of the time.

975. Several commenters state that it would be extremely burdensome to develop, at the system impact study stage, a reliable estimate of the number of hours of redispatch and the cost of the planning redispatch.[617] These commenters state that this would require substantial investment in probabilistic studies of equipment availability and extensive training of personnel and expansion of data collection, yet still would not provide reliable estimates of the number of hours or costs of the service. MISO states that at a minimum, this would require two years to implement.

976. EEI asserts that conditional firm service should be determined based on system impact studies and facilities studies so that the customer can evaluate the costs of upgrades versus the lack of reliability of the conditional firm service. EEI and others also propose that conditional firm service only be available when upgrades cannot be completed during the term of service or during the period prior to completion of transmission upgrades.[618] In its reply comments, Bonneville disagrees that conditional firm service should be an interim service available only when the customer has agreed to pay for upgrades, stating that such a requirement would undercut the value of conditional firm service. Bonneville adds that, for example, the costs to build upgrades in order to resolve a constraint in a two-month period could raise the costs of the conditional firm service to a prohibitive level for little additional benefit to the customer.

Commission Determination

977. As we explain above, the Commission finds that both planning redispatch and conditional firm point-to-point service must be offered under certain circumstances for the provision of reliable and non-discriminatory point-to-point transmission service. We set forth below the parameters of this service, keeping in mind the concerns expressed by commenters.

978. First, the planning redispatch and conditional firm options need only be made available to customers who request firm point-to-point service of more than a year in duration. When the requested firm point-to-point service is not available and the customer agrees to a system impact study, the transmission provider must evaluate the planning redispatch and conditional firm option at the customer's request. If the customer requests study of the planning redispatch or conditional firm options, the system impact study must identify the following: (1) The system constraints, identified by transmission facility or flowgate, causing the need for the system impact study; (2) additional direct assignment facilities or network upgrades required to provide the requested service; (3) redispatch options, including an estimate of the incremental costs of redispatch and the relevant congested transmission facilities for which redispatch will be provided; and (4) conditional firm options, including the number of conditional curtailment hours and the specific system conditions during which conditional curtailment may occur. Transmission providers may recover the costs of studying these options through the system impact study agreement.

979. Second, we adopt limitations on the nature of the planning redispatch and conditional firm options to reflect the two different types of customers that may request the service: customers who support the construction of upgrades and those who do not.

980. For customers supporting the construction of upgrades, the planning redispatch or conditional firm options will serve as a bridge until upgrades are constructed to remedy the congested transmission facilities. For these customers, the transmission provider must offer planning redispatch or conditional firm service until the time when the upgrades are constructed. The conditions or redispatch applicable to this period must be specified in the service agreement and are not subject to change. We impose this requirement

[616] *E.g.*, Xcel, PPM, and BP Energy.

[617] *E.g.*, EEI, Southern, TVA, SPP, E.ON, and MISO.

[618] *E.g.*, APPA, PNM–TNMP, and Southern.

because customers who commit to support transmission upgrades are typically those financing and constructing new resources. These customers require certainty both with regard to upgrade costs and, before upgrades can be constructed, the redispatch requirements or curtailment conditions that may apply to their service. We disagree with Williams and BP Energy that requiring transmission providers to offer this bridge product will present more opportunities for undue discrimination. As we note above, available information on transmission providers' current uses of redispatch and curtailment plans for their retail native load indicates that the mechanisms are used for relatively short periods of time until upgrades are completed to resolve the transmission insufficiencies. Comparable services for long-term point-to-point customers should therefore be similarly limited to shorter time periods or otherwise linked to transmission upgrades.

981. For customers choosing not to support the construction of new facilities, the planning redispatch or conditional firm options also must be made available as a reassessment product, *i.e.*, subject to certain limitations. Although many transmission providers argue that planning redispatch and conditional firm service should be offered only to customers who seek to upgrade the grid, we disagree. We find that there are legitimate circumstances under which customers may not choose to support system upgrades—either because the costs of construction are too high or because the term of service (*e.g.*, less than five years) does not merit the construction of additional facilities. We will therefore make planning redispatch and conditional firm service available to such customers, but subject to certain limitations to reflect the nature of the services. Specifically, we must select a limitation on the term for the conditions that permit interruption or redispatch, given that, for these customers, the term is not circumscribed by the period during which upgrades are constructed. We adopt two years as the appropriate time period to allow the transmission provider to reassess the conditions under which planning redispatch or conditional firm service is provided. The transmission provider will retain the right to reassess the planning redispatch and conditional firm option after the first two years of service, and every two years thereafter. The transmission provider shall reassess (1) the redispatch required to keep the service firm or (2) the conditions or hours under which the transmission provider may conditionally curtail the service. The customer will receive service for the requested term unless the transmission provider determines through its biennial reassessment that the firm point-to-point service can no longer be reliably provided. The customer may also choose to terminate the service at the time of reassessment if the service no longer meets it needs.

982. We select two years as providing a reasonable balance between the concerns of potential customers and transmission providers. We recognize that a shorter period would increase the reliability of predictions, as sought by certain transmission providers, but find that a two-year period is consistent with the bridge concept, given that two years is often less than the typical time to construct new facilities. While this is a shorter period than some transmission customers would desire, customers who require greater certainty over the long-term can obtain that certainty by agreeing to support the construction of new facilities. In the long run, all firm transmission customers, including conditional firm customers, should support the expansion of the grid to reliably serve load.

983. We decline to adopt any of the suggestions to address unique circumstances that may arise in which upgrades are prohibitively expensive. Specifically, we will not adopt Constellation's suggestion that customers be able to rebut the presumption that required upgrades are just and reasonable. In this Final Rule, we provide customers with the option of obtaining planning redispatch or conditional firm service for a long term, with the ability to roll over a five-year or longer reservation, subject to a limitation that the underlying restrictions on the service, *i.e.*, the conditions for redispatch or curtailment, may be reassessed by the transmission provider every two years. We believe that this option is superior to that proposed by Constellation because it will provide the customer with rollover rights while ensuring that transmission providers can reliably operate their transmission systems. Additionally, since issues of lumpy capacity are present in the provision of transmission services generally, we will not address such issues in this Final Rule as they do not present issues unique to planning redispatch or conditional firm options.

984. Contrary to the assertion of several commenters, we believe that transmission providers would take greater risk in committing to conditions for the entire term of a 10-year conditional option than they take today in committing to provide unconditioned firm point-to-point transmission service for a similar period. Planning for reliable service for existing transmission customers is a difficult process, but it is much more difficult to plan over an extended long-term period for reliable service when the service is firm for most of the hours of the year and less firm for other hours. This is because many transmission providers use annual hourly peak load for two to 10-year planning purposes. They would need to substantially change their planning methods to ensure no change in service for a conditional firm customer that is not expected to be served during the peak hour. We therefore adopt a two year assessment window to provide an appropriate degree of flexibility for transmission providers' planning needs.

985. We acknowledge, however, that some commenters, such as Bonneville and Nevada Power, state that they may be able to provide conditional firm service over a period longer than two years, without the need for reassessment. The Commission encourages the provision of planning redispatch or conditional firm service for longer periods where it is practical. In the event a transmission provider is able to extend the assessment period, we will allow the transmission provider to waive or extend its right to reassess the availability of the option, provided that the waiver or extension is provided consistently for all similarly situated service.

986. With regard to timing of the study of planning redispatch and conditional firm options, the Commission finds that study of both options is appropriate in the system impact study. The obligation for the transmission provider to study planning redispatch options in the system impact phase is already present in the existing OATT.[619] The Commission clarifies in this Final Rule the specific requirements necessary to meet this obligation. Transmission providers, when requested by potential customers, must provide non-binding estimates of the incremental costs of planning redispatch and identify the relevant congested transmission facilities for which redispatch will be provided. Transmission providers will not be required to estimate the number of hours of redispatch that may be required to accommodate the requested service as proposed in the NOPR. The Commission is persuaded by commenters that such an estimate is of limited use to potential customers and is difficult, expensive and time consuming for transmission

[619] *See pro forma* OATT section 19.3.

providers to calculate with any accuracy.

987. Finally, the Commission disagrees that the study of planning redispatch options must necessarily go hand in hand with the study of the costs and construction requirements of facility upgrades. Again, the obligation to study planning redispatch in the system impact study is not new. Our action in reinforcing this existing obligation cannot violate comparability or, in itself, cause the slowing of study processes. We have moved to a later study of conditional firm options so that both options can be studied in tandem. Furthermore, we note that the structure of the reassessment product requires the study of both options at the system impact study phase, since by definition customers opting for the reassessment product are not likely to enter into a facilities study agreement. We acknowledge that the few changes that we are making to the planning redispatch obligation may increase requests for study of the option and certainly the new conditional firm option will need more study than in the past. While we recognize the tension between the adoption of requirements to speed study completion and the increase in studies' complexity caused by the conditional firm option,[620] we will not forego a beneficial new option for customers because of this tension. We expect that transmission providers will be diligent in completing the system impact studies and in bringing to our attention any difficulties in meeting deadlines caused by the study of the two options.

(B) Who Must Provide Planning Redispatch and Conditional Firm

NOPR Proposal

988. In the NOPR, the Commission requested comment on the applicability of these two options to transmission providers who operate as RTOs and ISOs. The Commission also requested comment on which resources should be required in the provision of planning redispatch. First, the Commission proposed that the planning redispatch requirement apply to the redispatch of the transmission provider's own generation resources, but not to obligate transmission providers to purchase new resources to provide the service. If a transmission provider cannot accommodate a long-term firm point-to-point transmission request through planning redispatch, the Commission proposed requiring the transmission provider to identify additional generators in other control areas that could relieve the constraint. The Commission also requested comment on whether the planning redispatch obligation should be expanded to require the use of network customer resources in addition to transmission provider resources or expanded to require that transmission providers contract to purchase off-system resources to facilitate the planning redispatch.

(i) Application to RTOs and ISOs

Comments

989. RTOs state that reforms regarding planning redispatch and conditional firm services are unnecessary in RTO markets with financial congestion management because these markets already provide sufficient redispatch inside RTOs and sufficient interconnection service for generators located at RTO boundaries to address the Commission's point-to-point service concerns.[621] Ameren and MISO add that the options could disrupt the distribution of financial transmission rights in RTO markets. Others disagree and argue that planning redispatch should be used by RTOs to define the current and future operational environment to ensure that systems are not overbuilt.[622] AWEA contends that, since RTOs and ISOs vary considerably in the services they offer, RTOs and ISOs should be required to demonstrate that their services are consistent with or superior to planning redispatch and conditional firm services. In particular, AWEA argues that RTOs that do not provide financial rights should be required to provide both of these services. Exelon states on reply that the Commission has proposed minor changes to the existing planning redispatch requirement that should not be impractical or too burdensome for RTOs to administer.

990. In its reply comments, California Commission adds that capping the frequency or costs of redispatch in an RTO market would inappropriately shift the costs of congestion to others. Although SPP has successfully used planning redispatch to facilitate short-term firm transmission service and to address interim circumstances associated with long-term firm transmission service,[623] it argues that the Commission's proposed expanded planning redispatch service would slow its batch processing of transmission service, require significant investment of time to evaluate the options given the scope of an RTO, and create speculative redispatch estimates at best. SPP adds that RTOs should simply assist the customer with identification of planning redispatch options so that the customer can bilaterally contract with the generation owners of its choice.

991. MISO adds that conditional firm is inconsistent with RTO market mechanisms, requires burdensome changes to curtailment protocols and reliability coordinator's procedures, and would impact every tool used in real time for congestion management in RTOs. In its reply comments, MISO adds that adoption of conditional firm service would require revisions to seams agreement protocols. California Commission states on reply that the added administrative complexity of conditional firm service is unnecessary in the CAISO because the ISO's transmission service model makes no distinction between firm and non-firm service and provides prospective new customers with information to objectively estimate curtailments. FirstEnergy and MISO express concern regarding disruption of existing RTO communication protocols if these services are required in RTOs.

Commission Determination

992. Notwithstanding the requirements of section IV.C of this Final Rule, the Commission finds that it would be inappropriate to require RTOs and ISOs with real-time energy markets to adopt the provisions for conditional firm point-to-point service. Customers transacting in RTOs and ISOs are able to buy through transmission congestion in the RTOs' real-time energy markets and need no prior reservation in order to access transmission. Voluntary curtailment in order to access transmission is thus not an attractive option given the range of options available for customers transacting in RTOs and ISOs. Further, in RTOs and ISOs with financial transmission rights, conditional firm service may disrupt the distribution of these rights. We therefore believe that there is no need to reform existing RTO and ISO procedures to satisfy concerns underlying the adoption of the conditional firm option.

993. The Commission directs, however, RTOs and ISOs that already

[620] In section V.D.5.a, we adopt a requirement that transmission providers post metrics on their performance in processing system impact studies and facilities studies.

[621] *E.g.*, MISO, PJM, California Commission, and ISO New England.

[622] *E.g.*, AWEA, Indianapolis Power Reply, and Exelon Reply.

[623] *Citing* Attachment AC of the SPP OATT (Optimal Reservation Processing Method for Short Term Firm Transmission Services).

provide planning redispatch pursuant to section 13.5 of the *pro forma* OATT to modify the relevant provisions of their tariffs consistent with our directives in this Final Rule.[624] RTOs and ISOs need not amend their tariffs if the Commission has previously found that these tariffs were just and reasonable without the inclusion of *pro forma* section 13.5 planning redispatch provisions. We will not require incorporation of the more limited planning redispatch obligations adopted in this Final Rule if RTOs and ISOs have already been excused from the planning redispatch obligations of the existing *pro forma* OATT.

(ii) Generation Resources Required for Planning Redispatch

Comments

994. Most commenters agree that resources in addition to the transmission provider's resources can and should participate in the provision of planning redispatch. Commenters differ as to whether this participation should be mandatory or voluntary. A few commenters maintain that participation by resources outside the transmission provider's control area could have adverse impacts on reliability in the control area.[625]

995. In arguing for mandatory participation, EEI and others contend that all generation resources owned or operated by all jurisdictional transmission customers in the control area or balancing authority area should be obligated to redispatch to accommodate new requests for service in order to avoid undue discrimination.[626] Exelon argues that transmission providers should redispatch resources of its network customers, subject to appropriate compensation. SPP contends that generation affiliated with transmission owners that have transferred functional control of their transmission assets to an RTO should not have any greater planning redispatch obligation than unaffiliated generation. In its reply comments, Entergy states that the Commission at a minimum should continue to allow network customers to request that transmission providers redispatch network customer resources in order for the customer to designate a new network resource.

996. Others argue for a least-cost economic dispatch to relieve real-time system constraints, including not only the transmission provider's own resources and those of its network customers, but also all non-affiliated resources both within and outside its footprint that choose to be included.[627] EPSA explains that this redispatch would: Require transmission providers to solicit offers from resources to provide energy and perhaps ancillary services; be based on a resource's offer of service and take into account generating resource and transmission operating limits; include performance assurance terms, unit commitment procedures, billing, compensation and bidding protocols, confidentiality protections, and information-sharing protocols; and dispute resolution procedures to avoid disputes rising to the level that would require judicial or regulatory intervention. AWEA supports Deseret's OATT provisions that require the transmission provider to relieve constraints by the least cost means, whether by seeking a change in generation output from the transmission provider's merchant function or from any other feasible generator. Williams suggests that independent generators must be allowed to participate in the provision of planning redispatch service through submission of a formulary rate to the transmission provider. If the Commission intends to have non-affiliated generators participate in planning redispatch, PPL states that the Commission should require transmission providers to negotiate agreements with generators on their systems.

997. TranServ, MidAmerican, and Nevada Companies support a planning redispatch service similar to that employed by the Mid-Continent Area Power Pool, whereby customers arrange for their own redispatch through bilateral or centralized energy markets and submit plans for approval to their transmission provider and reliability coordinator.

998. Several commenters discuss the need for market development in conjunction with the planning redispatch obligation. TranServ and Xcel state that the planning redispatch option may force transmission providers without generation assets to develop some form of energy market to arrive at the costs of redispatch. Southern and Progress Energy add that forced adoption of such a market would raise significant political opposition and be contrary to the Commission's commitment in the NOPR to avoid such restructuring.

999. EPSA, AWEA and PJM support such market development. When a generator in another control area is called upon to relieve a constraint in regions not administered by an RTO, PJM states that the Commission must direct the development of an alternate LMP pricing scheme to establish ''system marginal costs'' that are consistent with transparent generator pricing in RTO markets. EPSA and PJM argue that vertically integrated utilities in non-RTO areas should turn over functional control of their dispatch function to a disinterested entity or replicate the transparency by publishing generation dispatch. EPSA suggests that the Commission require this transparency to ensure nondiscriminatory redispatch.

1000. A few commenters state that any requirement for the transmission provider to purchase generation from outside the control area to facilitate planning redispatch is functionally unworkable and would adversely impact reliability.[628] EEI supports the Commission's proposal to have transmission providers identify off-system resources that could provide planning redispatch but requests clarification that no additional investigations or studies are required to identify these additional options. MidAmerican adds that the coordinated, open and transparent planning provisions of the NOPR should provide customers with the ability to identify off-system resources. EEI and Southern state that any redispatch on adjacent systems should be arranged by transmission customers and the service should be curtailed prior to other firm uses of the system if the off-system generator fails to perform. WAPA and Bonneville argue against the use of off-system redispatch, stating that lack of control over these resources could cause reliability problems on the originating transmission system. WAPA also believes that off-system redispatch would not provide the price certainty needed by customers because the redispatched megawatts will differ based on the transmission system parameters, and customers would be required to pay for any loop flow resulting from the off-system redispatch.

1001. In its reply comments, EEI adds that a requirement for transmission providers to solicit planning redispatch

[624] This includes the transmission provider's obligation to post monthly redispatch costs for each transmission facility over which planning and reliability redispatch are provided.

[625] *E.g.*, Ameren, PNM–TNMP, Xcel, and WAPA.

[626] *E.g.*, Southern, FirstEnergy, MidAmerican, and Community Power Alliance.

[627] *E.g.*, AWEA, Project for Sustainable FERC Energy Policy, Exelon, Powerex, Constellation, Williams, Sempra Global, PJM, EPSA, and Entegra Reply. Sempra Global contends that the Commission should require transmission providers to offer redispatch of non-affiliated resources both within and outside its footprint, subject to pre-existing contractual commitments.

[628] *E.g.*, Xcel, PNM–TNMP, and Public Power Council Reply.

proposals from generators inside and outside their control areas would require that transmission personnel become involved in generation and power sales matters in violation of the Commission's Standards of Conduct. Duke argues on reply that such an approach would require that third party generators reveal their costs to the transmission provider and that a means of estimating costs for all generators subject to planning redispatch would need to be set forth in the *pro forma* OATT.

1002. LPPC, APPA and TAPS oppose any requirement that transmission providers redispatch their network customer's resources as well as their own to provide planning redispatch, stating that this action would appropriate resources beyond the Commission's jurisdiction, result in endless conflict between transmission providers and resource owners, and interfere with network customer's use of their limited resources.

Commission Determination

1003. Order No. 888 compelled transmission providers to provide planning redispatch from their own resources.[629] The Commission declines to expand that obligation to require transmission providers to solicit third party resources in order to provide planning redispatch. We will, however, require transmission providers to identify in the system impact study (1) generation resources located within the transmission provider's control area, including its own resources, that can relieve the congested transmission facility at issue, and (2) the impact of each identified resource on the congested facilities, *e.g.*, the generator shift factor. The resources identified in the system impact study need not be available to provide the redispatch. Customers must simply be provided with the set of generators that could, if available, make a significant contribution toward relieving the constrained facility at issue. This information, in addition to the information provided through congestion planning studies, will provide the necessary information to customers wishing to solicit third party resources to relieve congested facilities in order to accommodate long-term firm point-to-point service. We note that this information is readily accessible by the transmission provider, as it is the same information used to determine *pro rata* curtailments of firm resources in contingency situations.

1004. In addition to identifying generation resources within the control area, the Commission also requires identification of resources outside the control area that may be able to relieve congested transmission facilities. To the extent the transmission provider is aware of generation resources outside of its control area that can relieve the constraint, the transmission provider must inform the customer of these resources. To be clear, this does not require the transmission provider to undertake any additional investigation or study to identify generation options located outside of the control area. To the extent the transmission provider has such information, however, it must provide it to the customer.

1005. The Commission will not mandate the use of network customer resources or other third party resources in the provision of planning redispatch.[630] If they choose, network customers and third parties may voluntarily provide planning redispatch services. A seller is free to post its price to relieve a specific congested transmission facility and its ability to relieve the congestion. To facilitate provision of such service by third parties, we direct transmission providers to modify their OASIS sites to allow for posting of these third party offers. Accordingly, we direct transmission providers to work in conjunction with NAESB to develop this new OASIS functionality and any necessary business practice standards. Transmission providers need not implement this new OASIS functionality and any related business practices until NAESB develops appropriate standards.

1006. Customers may then contract in advance with these third parties or use their own resources to secure planning redispatch services in lieu of or in addition to service from the transmission provider. In this way, customers can arrange for their own planning redispatch through bilateral markets and submit plans for approval to their transmission provider and reliability coordinator. The arrangements must, however, be sufficiently detailed and coordinated with the transmission provider to ensure that reliability is maintained.

1007. We therefore direct in this Final Rule that transmission providers work with customers to facilitate the use of third party generation, where available, in provision of planning redispatch. This entails review of redispatch plans submitted by customers, coordination between the transmission provider and reliability coordinator, and signaling third party generators when the redispatch is needed. These arrangements will require close coordination between the transmission provider, third party generators and transmission customers. The arrangements must be sufficiently detailed to allow the transmission provider to maintain reliability. Although we will not allow transmission providers to unreasonably deny customers the use of third-party resources to provide planning redispatch, it is the customers' ultimate responsibility to ensure that all the necessary contractual and technical arrangements are in place to maintain reliability. We clarify for Entergy that this would allow transmission providers to continue to provide planning redispatch for network customers from the network customers' resources. We also clarify that transmission providers may curtail transmission customers if a third-party resource fails to perform its contractual redispatch obligation. This or any other remedy for non-performance must be specified in writing between the parties prior to commencement of the service.

1008. For the reasons discussed below regarding the TDA proposal, we decline to adopt the bid-based redispatch model suggested by EPSA. In section V.C.1 of this Final Rule, we similarly reject proposals to impose LMP and independent control of the dispatch function. We believe that a bid-based generation market design is not necessary to remedy undue discrimination in the provision of transmission service. We also believe that our modifications to the planning redispatch requirement, including the OASIS changes directed herein and the requirement that transmission providers make available information on generators capable of providing planning redispatch, will provide potential customers with greater information about redispatch choices and enable greater opportunities for planning redispatch and comparable service.

[629] *See pro forma* OATT section 13.5. With respect to SPP's assertion that transmission owners' affiliated generation should have no greater redispatch obligations than unaffiliated generation in RTOs, we find that relevant redispatch obligations in the RTO tariff and transmission owners' tariffs govern this issue. *See Southwest Power Pool, Inc.*, 110 FERC ¶ 61,133 at P 17 (2005) (rejecting proposed provisions that would have removed the obligation for transmission owners to provide planning redispatch).

[630] Network customers will continue, however, to be obligated to make their network resources available to the transmission provider for reliability redispatch in real time.

(C) Pricing of Planning Redispatch

NOPR Proposal

1009. In the NOPR, the Commission sought comment on which type of redispatch pricing would ensure effective use of the planning redispatch option. The Commission described one type of pricing, a formula rate, to include a MW quantity, the incremental cost of fuel at the point of delivery, and the decremental cost of fuel at the point of receipt capped at the price of fuel. The Commission sought further comment on whether it would facilitate planning redispatch to base calculations of the various costs for input into the formula on the difference between the cost of ramping up a generator at the point of delivery and ramping down a generator at the point of receipt. The Commission also described a redispatch pricing proposal to calculate redispatch charges monthly and charge the higher of actual redispatch costs or the OATT rate each month made by PacifiCorp in response to the NOI.

Comments

1010. While many specific comments were received on the pricing of planning redispatch service, there is little consensus on this subject. Several commenters state that pricing challenges associated with planning redispatch are difficult if not insurmountable.[631]

1011. MidAmerican and EEI argue that the current cap on planning redispatch at the costs of upgrades should be removed because a customer will always choose planning redispatch and the risks that redispatch costs exceed construction costs falls to the transmission provider and is either unrecoverable or passed on to other customers.

1012. According to several commenters, requiring the transmission provider to establish a standard fee for planning redispatch, either on the overall system or on a path-by-path basis, would accomplish cost certainty for the customer and hold the transmission provider accountable for the accuracy of the studies used to assess redispatch requirements.[632] These commenters support a standardized formula-rate for planning redispatch or a capped amount at, or close to, the embedded cost rate. Entegra and TransAlta state that the redispatch pricing proposal may allow transmission providers discretion to charge redispatch costs without providing customers a practical way to verify that claimed redispatch costs have actually been incurred. PGP states that the Commission should allow for regional differences in planning redispatch pricing. APPA does not support a departure from the current redispatch pricing approach, while Seattle states that the existing section 13.5 is unworkable because the cost of planning redispatch is difficult to calculate for both historical and near-term operating horizons, much less over a multi-year planning horizon.

1013. EPSA and AWEA believe that the pricing mechanisms suggested in the NOPR would be open-ended and highly variable over the duration of the reservation and, thus, not meet the needs of customers. EPSA and AWEA assert that, consistent with Commission precedent,[633] a utility must identify and justify its costs in excess of average system costs before service commences in a manner that meets the customer's needs to charge a rate in excess of average system costs, *i.e.*, some customers may require a firm estimate upfront to obtain financing while others may be willing to negotiate a rate based on estimates.[634] EEI states on reply that the policy in American Electric Power related to an expansion cost rate, which is inapposite to redispatch costs because the costs of new construction are easier to estimate in advance than are the costs of planning redispatch. EEI contends that the planning redispatch customer's interest in price certainty is not a sufficient basis for shifting costs to other customers or to the transmission provider.

1014. EPSA and AWEA suggest that, when the cost of planning redispatch is estimated to exceed the transmission rate, the transmission provider should offer either: a formula rate for incremental redispatch costs with the number of hours of redispatch, the resources to be redispatched and the conditions under which redispatch would occur defined in advance or, an incremental cost rate determined at the time of the reservation to cover the reservation period that may include a risk adder for the transmission provider. Morgan Stanley argues that planning redispatch options should include the following: Redispatch priced at a market index; where market prices are not available, the price should be the incremental costs; full cost pricing should be allowed for ''life of service'' (total dollar cost for unlimited redispatch over the term of a contract) or fixed rate contracts for actual redispatch agreed to at the time of contracting; and redispatch costs provided from a third-party provider. Morgan Stanley opposes ''higher of'' pricing that would allow for monthly charges for redispatch costs or long-term firm transmission service rate.

1015. In contrast, many transmission providers and EEI ask the Commission to allow for recovery of actual costs of redispatch, rather than the estimated costs, with the customer obligated to pay all costs.[635] Since providing accurate estimates of redispatch costs and hours are difficult, especially with respect to longer-term service requests given the variability of fuel costs, transmission providers contend that they should not bear the risks of inaccurate cost estimates for a service that benefits only the point-to-point customer.[636] Indianapolis Power adds that planning redispatch should be priced to discourage inefficient dispatch of generation. In its reply comments, PPM agrees that planning redispatch is unworkable without certainty of cost recovery for the transmission provider, but believes that with enough information customers can evaluate the risks and gain certainty required for a workable product.

1016. Southern argues that the current pro forma OATT language unreasonably places the risk of uncertainty in estimating redispatch costs on the transmission provider and its native load customers, contrary to basic cost causation principles and native load protections in Order No. 888. Southern suggests that the Commission follow the approach in the Deseret and SPP tariffs, which allow for the transmission provider to recover its actual costs of redispatch. Ameren states that a standard per kWh fee is simpler to administer, but should be structured to recover all of the costs of planning redispatch, including opportunity costs.

1017. Various commenters argue that the Commission should allow the following redispatch costs to be recovered: Fuel; variable operations and maintenance; increased maintenance costs due to cycling; start-up and ramp-down costs; emergency purchases; costs of additional operating reserves; environmental costs; and lost opportunity costs.[637] MidAmerican also argues that a transmission provider should be able to recover the costs of

[631] *E.g.,* Powerex, Manitoba Hydro, Seattle, NRECA, Ameren, and E.ON.

[632] *E.g.,* Utah Municipals, Public Power Council, PPM, Entegra, Constellation, TransAlta and TAPS.

[633] *American Electric Power Service Corp,* 64 FERC ¶ 61,279 (1993) (*American Electric Power*).

[634] *Id.* at 62,976.

[635] *E.g.,* Southern, MidAmerican, Entergy, FirstEnergy, Ameren, Nevada Companies, E.ON, and South Carolina E&G.

[636] *E.g.,* EEI, Entergy, LPPC, NRECA, MidAmerican, Ameren, and FirstEnergy.

[637] *E.g.,* LDWP, EEI, Ameren, MidAmerican, and Southern.

redispatch energy purchased in response to a pre-schedule by a planning redispatch customer regardless of schedule changes by the customer and regardless of any *pro rata* curtailments affecting such customers due to system reliability.

1018. EEI and Southern argue that customers that choose planning redispatch should pay the cost of transmission service and the cost of redispatch. EEI asserts that allowing recovery of both costs is not prohibited ''and'' pricing because the services differ, as one is provided by the transmission system and one is provided by generators, and native load and network customers pay *pro rata* shares of reliability redispatch costs to relieve constraints on the system as well as the basic costs of transmission service. TAPS and TDU Systems take the opposite view and state that the Commission should require planning redispatch pricing consistent with the Commission's ''higher of'' or ''or pricing'' policy. In addition, they state that the redispatch charges must be capped up front at fixed dollars and hours at or close to the embedded cost rate.

1019. Arkansas Commission agrees with the PacifiCorp pricing method in which redispatch costs are recalculated monthly and customers are charged the higher of the redispatch cost rate or the monthly OATT transmission rate. TAPS states that this method avoids ''and'' pricing, but does not address the complexity or risks associated with determining redispatch costs over a long period. APPA argues that the PacifiCorp proposal, if applied after the fact, could lead to uncertainty and disruption of market transactions. Southern opposes any pricing method that caps the total costs that a planning redispatch customer would bear, including the PacifiCorp proposal, stating that caps allow the planning redispatch customer to shift costs to the transmission provider and its native load customers.

1020. E.ON points to an inherent problem in planning redispatch pricing: Transmission providers should be kept whole with regard to actual real-time redispatch costs but customers may not know until after the fact that the planning redispatch was not economic for their purposes. E.ON foresees difficulty in allocating redispatch costs among multiple planning redispatch service customers and requests that the Commission adopt a specific methodology for calculating each request's impact on the system.

Commission Determination

1021. Although there is no consensus regarding which form of pricing methodology is most appropriate for planning redispatch service, there is general agreement among the commenters that the current pricing rules fail to meet the needs of either customers or transmission providers and consequently fail to make planning redispatch an attractive means for customers to obtain access to the grid. Transmission providers and customers both express concern regarding the variability of redispatch costs. Customers worry that actual redispatch costs may greatly exceed estimates and thus seek cost certainty over the term of the service. Conversely, transmission providers claim that accurately estimating future redispatch costs for long duration service is extremely difficult. In fact, transmission providers state that the uncertainty in forecasting long-term redispatch costs is much greater than any uncertainty inherent in determining the costs of transmission upgrades.

1022. The Commission has carefully considered these comments and agrees that the current method for pricing planning redispatch service is no longer just, reasonable or not unduly discriminatory. The Commission takes three principal actions to address the concerns of customers and transmission providers.

1023. The Commission therefore adopts a new pricing method for planning redispatch service. We will no longer require the capping of redispatch costs over the term of the service at the costs of expansion. This change is inextricably linked with the change in the obligation to provide planning redispatch, *i.e.*, the removal of the open-ended requirement to provide planning redispatch as long as it is more economical than transmission upgrades. We have shortened the planning redispatch obligation to apply before upgrades are built as a bridge product or to apply as part of a reassessment product. In prior cases, the Commission expressed the view that capping cost recovery for long-term transmission service at the costs of expanding the transmission system provides an incentive for transmission providers to undertake expansion when it is warranted.[638] The expansion cost cap should not be applied to the bridge product because (1) upgrades will in fact be constructed and should be paid for by the customer under the ''higher of'' policy, and (2) an expansion cost cap does not serve as an incentive for expansion because the transmission provider already will have started the process of building transmission facilities for the customer who opts for the bridge product. If planning redispatch is provided as part of a reassessment product, the customer has chosen not to pay for upgrades and thus, the expansion cost cap cannot provide an incentive for transmission expansion.

1024. We will therefore adopt a new pricing methodology. We believe that the PacifiCorp proposal described in the NOPR is the one that balances the competing concerns of transmission customers and transmission providers. Under this pricing methodology, customers will have the option of paying (1) the higher of (a) actual incremental costs of redispatch or (b) the applicable embedded cost transmission rate on file with the Commission or (2) a fixed rate for redispatch to be negotiated by the transmission provider and customer and subject to a cap representing the total fixed and variable costs of the resources expected to provide the service. If the customer selects the higher of incremental cost or the embedded-cost rate, the transmission provider shall calculate the costs of redispatch monthly and charge the higher of redispatch or the embedded cost rate each month.

1025. We have selected a monthly comparison of embedded costs and redispatch costs on the basis of a number of factors. The Commission has rejected basing the comparison on the life of a long-term firm transmission contract.[639] For administrative efficiency, a transmission provider should be allowed to close its books and not be subject to possible refunds or surcharges at the end of its billing cycle. The standard billing cycle in the industry is one month. Allowing transmission providers to finalize accounting entries will provide certainty to both the transmission provider with regard to revenue recovery and to the transmission customer with regard to cost exposure. We therefore find that a monthly comparison of embedded and incremental cost is appropriate. This method retains ''higher of'' pricing for customers, but does not subject transmission providers to open-ended liability for refunds and otherwise should make planning redispatch service more attractive for transmission providers to provide. Further, given that redispatch often occurs only in selected time periods within a year (*e.g.*, during

[638] *See, e.g., Florida Power & Light Co.,* 70 FERC ¶ 61,158 at 61,484 (1995).

[639] *Id.* at 61,483.

the peak season, shoulder months, *etc.*), it is just and reasonable to allow the transmission provider to perform the higher of calculation in each month when the service is provided, not spread those costs over the entire year.

1026. For purposes of calculating planning redispatch charges, incremental costs shall include fuel or purchase power costs caused by ramping up generator(s) at the point of delivery and ramping down generator(s) at the point of receipt. Additionally, where applicable, transmission providers may specify in customer service agreements other incremental costs for inclusion in the monthly actual incremental costs, including opportunity costs. Identification and derivation of these costs must be included in the service agreement. We reiterate our existing requirement that all information necessary to calculate and verify opportunity costs must be made available to the transmission customer.[640] We clarify that the actual costs of redispatch need not be determined annually or at the time that the service agreement is executed; rather, actual redispatch cost should be determined on a monthly basis.

1027. With respect to MidAmerican's request to be able to recover the purchase power costs for a customer requiring planning redispatch, we reiterate that transmission providers are under no obligation to purchase power to provide planning redispatch services. Should the transmission provider take on the obligation to contract with a third party to provide planning redispatch at the customer's request, however, the customer should be obligated to pay the purchase power costs, including any reservation charge for the power. The flow-through of purchase power costs must be negotiated between customers and transmission providers in a stand-alone agreement if the transmission provider agrees to make purchases on the customer's behalf.

1028. The Commission will not adopt proposals suggested by several transmission providers to allow for recovery of the embedded cost transmission rate and the full costs of redispatch. The Commission's ''higher of'' pricing policy prohibits the transmission provider from charging both embedded costs and incremental costs such as redispatch costs.[641] We reject EEI's assertion that we should adopt such pricing because native load and network customers pay a load ratio share of redispatch costs and the embedded cost transmission rate. Planning redispatch differs from the reliability redispatch for which transmission providers are only obligated to provide network customers with ability to avoid real-time curtailments. Rather, planning redispatch is a means of creating additional transmission capacity,[642] not a generation service, and thus planning redispatch is appropriately priced by applying the Commission's ''or'' pricing policy. We decline to revisit that longstanding policy in this rulemaking.

1029. With respect to concerns that the expansion cost cap was adopted to provide rate certainty to customers over the term of the service,[643] we believe that the modified pricing policy adopted here will continue to provide appropriate certainty to customers, while also allowing transmission providers to recover just and reasonable costs. For customers purchasing the bridge product, the cost of redispatch will be incurred only during the initial term of the service agreement while new facilities are being constructed. During this term, the cost of redispatch service represents a legitimate cost of providing the service and therefore should be fully recoverable under the higher of policy. Although it is true that redispatch costs are difficult to project, and hence create uncertainty for customers, this does not mean that the transmission provider should not be allowed to recover the legitimate and verifiable costs of providing the service. Moreover, if the customer desires greater certainty regarding redispatch costs during this period, it can elect the fixed rate option discussed above and negotiate a fixed redispatch charge with the transmission provider. Once upgrades are constructed, however, the customer will receive the certainty of paying a fixed rate for transmission costs and, importantly, any expansion cost will be fixed at the time the initial service agreement is signed. Finally, for customers who do not select the bridge product because they do not want to fund upgrades, it would be unreasonable to cap the cost of redispatch at the cost of upgrades. In such an instance, the customer has elected to forego the price certainty that can be gained by funding the upgrades to remove the constraint that is causing the transmission provider to incur redispatch costs.

(D) Standards of Conduct and Planning Redispatch

NOPR Proposal

1030. In the NOPR, the Commission requested comment on the interaction of planning redispatch requirements with the Commission's Standards of Conduct.

Comments

1031. Commenters generally argue that the independent functioning requirement and the information sharing prohibitions under the Standards of Conduct are irreconcilable with the expanded planning redispatch proposal in the NOPR.[644] Southern, TranServ and Progress Energy contend that the planning redispatch option would require close coordination and communication with market participants including the marketing or energy affiliate, which may create confidentiality and Standards of Conduct problems. For instance, they state that close coordination and sharing of non-public transmission and customer information would be required to determine the generating units that can be redispatched, the impact that planned and forced outages of redispatched generators will have on the availability of transmission service and the transmission line loadings, and the costs of redispatch. Some commenters request that the Commission adopt an exception to the Standards of Conduct to permit communication between transmission providers and marketing and energy affiliates, acting as generation operators, for the transmission provider to instruct the generation operator to vary its generator's output.[645]

1032. MidAmerican suggests that it is unlikely that any communication protocols could be established that would both comply with the Commission's current Standards of Conduct and permit a transmission provider to coordinate with its marketing affiliate employees to arrange planning redispatch. Rather, MidAmerican argues that the transmission customer would have to waive the Standards of Conduct to enable the transmission function employees to share the necessary information with their marketing affiliate counterparts.

[640] *See* Order No. 888 at 31,740.

[641] *See Pennsylvania Electric Company*, 58 FERC ¶ 61,278, 62,871–75, *reh'g denied*, 60 FERC ¶ 61,034 (1992), *aff'd sub nom. Pennsylvania Electric Co.* v. *FERC*, 11 F.3d 207 (D.C. Cir. 1993); *see also Entergy Services, Inc.*, 71 FERC ¶ 61,139, 61,452 (1995) (regarding the pricing of redispatch service, the Commission stated ''[i]t is a well-settled matter that the Commission will not authorize ''and'' pricing, *i.e.*, embedded cost pricing plus opportunity (incremental) cost pricing.'').

[642] Order No. 888A at 30,267.

[643] *Florida Power & Light Co.*, 70 FERC ¶ 61,158 at 61,483 (1995).

[644] *E.g.*, Nevada Companies, Community Power Alliance, Progress Energy, LPPC, Southern, WAPA, and APPA.

[645] *E.g.*, E.ON, Ameren, and APPA.

1033. Other commenters argue that violations of the Standards of Conduct can be avoided by various means. PPM suggests that publication of redispatch costs similar to ancillary service costs and elimination of case-by-case sharing of information between the transmission provider and the generation operators would avoid Standards of Conduct issues. MidAmerican states that sole reliance upon bilateral agreements with third parties to provide planning redispatch would resolve the need to modify the Standards of Conduct. In their reply comments, Utah Municipals state that they do not believe the Standards of Conduct pose a barrier to provision of planning redispatch since transmission providers redispatch to serve their own loads currently, but that if so the Commission should make small modifications to the standards.

Commission Determination

1034. The Commission does not believe that any changes to its Standards of Conduct are required for transmission providers to implement the planning redispatch provisions adopted in this Final Rule. The information at issue, *e.g.*, generation redispatch cost, is held by the marketing affiliate and there is no prohibition under our Standards of Conduct on the marketing affiliate transferring such information to the transmission provider. The information sharing prohibitions under the Standards of Conduct are ''one way,'' *i.e.*, they restrict only communications of non-public transmission information from the transmission provider to the marketing affiliate, not vice versa. Therefore, the flow of information from marketing affiliates to transmission providers relating to the costs and availability of generation resources for planning redispatch is not prohibited under the Commission's Standards of Conduct.[646]

1035. We next turn to the flow of information from the transmission provider to the marketing affiliate. Initially, in order for transmission providers to evaluate planning redispatch options, they must identify the impacted transmission facilities, *e.g.*, flowgates, and determine the marketing affiliate's generators that could provide redispatch over those facilities. Transmission providers already have this information to enable them to provide least cost reliability redispatch. However, transmission providers need not provide information regarding the impacted transmission facilities to its marketing affiliates. Rather, in order for transmission providers to evaluate the future availability of redispatch and estimate the costs of redispatch, they need only tell the marketing affiliate which of its generators would be suitable for redispatch, thus identifying those that require study. This sharing of information relating to the marketing affiliate's generation is not prohibited by the Commission's Standards of Conduct.

1036. In addition, the transmission provider may also need to provide its marketing affiliate with transmission-related information from the transmission customer's service request, such as service quantity and term, to determine the required duration and amount of the redispatch required. We find that such information provided from the transmission provider to the marketing affiliate is not a prohibited transfer of non-public information because such details of the transmission customer's service request are available via OASIS. The only customer transmission request information not readily available via OASIS is the source and sink information.[647] We see no need for the transmission provider to provide such masked source and sink transmission information to its marketing affiliate as part of this redispatch evaluation process. We do not believe that any further information need be provided by the transmission provider to their marketing affiliates to evaluate the generators available for planning redispatch and their costs. Accordingly, we find there is no need to create an exception to the Standards of Conduct for the sharing of this generation-related information and publicly available transmission customer request information.

(E) Attributes of Conditional Firm

NOPR Proposal

1037. In the NOPR, the Commission described conditional firm service as a modified form of point-to-point service that includes non-firm service in a defined number of hours of the year when firm point-to-point service is not available. The Commission proposed that the conditional firm service agreement would identify the conditional curtailment hours and include an annual or monthly cap on those hours. The Commission further proposed that conditional firm service would be curtailed before firm uses until such times as the conditional curtailment hours were exceeded, after which time the service would be treated as firm. The curtailment priority during the conditional period was proposed as the same as secondary network service. The Commission proposed that customers using the conditional firm option would pay the long-term firm point-to-point rate. The Commission also proposed that conditional firm service qualify for rollover rights, provided that it meets the other rollover right conditions proposed in the Final Rule.

(i) General Terms and Conditions

Comments

1038. Most commenters support pricing conditional firm service at the long-term firm OATT rate and no commenter suggested a different pricing method. Nevada Companies and Bonneville state that the customer seeking conditional firm service should pay the actual costs of the study required to provide the number of conditional curtailment hours.

1039. EPSA and AWEA support the following components of the Commission's conditional firm proposal: Conditional firm is available only to customers that first request long-term service; it would provide a year round, long-term product that is firm during all hours of the year except at well-defined periods when the transmission provider is unable to provide the service; and, in all hours that are not conditional, conditional firm service would be treated as any other firm service with the same curtailment priority as long-term firm network and point-to-point rights.

1040. EEI proposes that conditional firm service be firm in periods when firm service is available according to ATC calculations and non-firm, with a monthly non-firm curtailment priority, for periods when firm ATC is not available. CREPC, Exelon and MidAmerican argue that the Commission should not require conditional firm service until all attributes of the service are clearly defined and key implementation issues are resolved, including modification of NAESB and NERC processes. NAESB states that the Commission can reduce the amount of time required to develop OASIS and transmission loading relief protocols by clearly defining the conditional firm service.

1041. In its supplemental comments, EEI states that the Commission should not require all transmission providers to adopt terms and conditions for conditional firm service that are only workable for some systems, *e.g.*, transmission providers in the Western Interconnection using the rated path

[646] 18 CFR 358.5.

[647] *See Open-Access Same-Time Information System and Standards of Conduct*, 83 FERC ¶ 61,360 at 62,456 (1998), *reh'g denied*, 86 FERC ¶ 61,139, *reh'g denied*, 87 FERC ¶ 61,382 (1999).

methodology compared to many in the Eastern Interconnection using a flow-based methodology; rather, the Commission should allow flexibility in the offer of conditional firm service so that transmission providers are not foreclosed from offering the service.

1042. Several commenters state that transmission providers and customers collectively should design the conditional firm service that best accommodates their respective needs.[648] In supplemental comments, Bonneville states that the transmission provider, not the customer, must determine the conditions to offer in response to a given request. Bonneville also requests that the Commission clarify that there would be no separate queue for conditional firm service.

Commission Determination

1043. The Commission adopts the conditional firm option as a modified form of long-term firm point-to-point service that includes less-than-firm service in a defined number of hours of the year or during defined system conditions when firm point-to-point service is not available. The service can be curtailed solely for reliability reasons during the defined system conditions or defined number of hours. We reject EEI's suggestion to use a monthly non-firm curtailment because it would allow for curtailment of the conditional service for economic reasons.

1044. In this Final Rule, we define the minimum attributes of the conditional firm option rather than allow individual transmission providers to develop any form of service that could conceivably be labeled conditional firm service. The Commission has been considering a conditional firm product and has been discussing it with the industry for some time. In early 2005, the Commission held a technical workshop to:

> Work with market participants to develop clear definitions for additional wholesale electric transmission services, *e.g.*, conditional firm transmission service, develop applicable pro forma tariff language that could be included in public utilities' open access transmission tariffs and address attendant issues.[649]

Although commenters in that proceeding stated that the Commission need not require new services in transmission providers' OATTs because they would be voluntarily developed,[650] no individual transmission provider developed new services in response to the workshop. In fact, seemingly, only one transmission provider in the Eastern or Western Interconnection offers a service that is similar to the conditional firm service adopted in this Final Rule.[651]

1045. Since the issuance of the NOPR, the Commission has provided the industry with three formal opportunities to provide comments on implementation of the conditional firm option. The Commission held a technical conference on implementation issues after issuance of the NOPR and held many informal technical discussions with industry representatives. We have taken these steps in order to make the most reasoned decision concerning the minimum attributes of the conditional firm option. These conferences and workshops have been helpful and have informed our decision on the minimum attributes of conditional firm service. As noted herein, although we are establishing certain minimum attributes, we also allow for some measure of flexibility in provision of the service. We will not, however, approve conditional firm as a concept only. Given our past experience, this would provide little benefit to customers seeking to use the service and no certainty to transmission providers seeking to comply with our regulations.

1046. Further, as discussed in more detail below, we disagree that NERC must modify its processes in order to allow transmission providers to implement this product. However, we will allow for a sufficient period of time for development of business practices and tracking mechanisms to implement the product. We recognize that there may be some regional variation in the way transmission providers approach the provision of conditional firm service beyond the minimum attributes that we establish in this Final Rule. Thus, we do not direct that transmission providers work with NAESB to develop business practices for implementation of the conditional firm service. Rather, we direct transmission providers located in the same region to coordinate such development among themselves. We also encourage participation of non-public utility transmission providers in the region and interested transmission customers in the development of these business practices. Public utility transmission providers should make efforts to include these interested parties in their regional coordination efforts. We direct transmission providers to implement these mechanisms and business practices within 180 days after the publication of this Final Rule in the **Federal Register**.

1047. The Commission adopts the proposal in the NOPR that customers using the conditional firm service pay the long-term firm point-to-point rate. We will not allow complete flexibility in defining the conditional firm option as suggested by EEI because such an option could provide a substantially lower quality service for which transmission providers would be able to recover the long-term firm rate. We also reject EEI's proposal that the service be a mix of firm and non-firm periods. We envision the conditional firm option as one in which firm service is available most of the period of a year. EEI seems concerned about tailoring the product to situations where congestion is so acute that the ''conditions'' require frequent interruptions. We do not believe this concern is well founded. Because a conditional firm customer is obligated to pay the long-term firm point-to-point rate, we assume that few, if any, customers would accept the service in circumstances where the interruptions (or ''conditions'') are so frequent or pervasive to make the service unattractive.

1048. Finally, we clarify for Bonneville that customers seeking the conditional firm option must first request long-term firm service. When ATC is unavailable, the transmission provider must study the conditional firm option at the customer's request. There is no separate queue for the conditional firm option.

(ii) Specified System Conditions and Conditional Hours

Comments

1049. Several transmission providers state that they cannot accurately predict the conditional curtailment hours because there are too many variables to consider and ATC analysis does not provide this level of granularity.[652] These commenters contend that load flow modeling for a wide range of

[648] *E.g.*, LPPC Supplemental, PPL Supplemental, Williams Supplemental, Community Power Alliance Supplemental, Entergy Supplemental, and Southern Supplemental.

[649] Potential New Wholesale Transmission Services, Notice of Final Agenda for Technical Workshop, 70 FR 12865 (Mar. 16, 2005).

[650] *E.g.*, Bonneville Workshop Comments at 1–2 (April 13, 2005) (stating that Bonneville believes the result of the workshop ''will be the development of one or more new transmission products.''), TAPS Workshop Comments at 2 (April 13, 2005) (suggesting that the Commission should invite and consider proposals by individual utilities rather than act by rulemaking).

[651] In the NOPR, the Commission noted PacifiCorp's 2002 modifications to partial interim service. *See* NOPR at P 319 n.298. PacifiCorp's service is similar to that proposed by EEI with the exception that customers are charged a pro rated long-term firm rate.

[652] *E.g.*, Imperial, Duke, Progress Energy, MidAmerican, PNM–TNMP, Southern, and EEI.

possible system conditions required to estimate the conditional curtailment hours would be complex, time-consuming and costly. Given this concern, Southern, PNM–TNMP, and MidAmerican state that any conditional firm service should be subject to a ''reasonable efforts'' standard and not represent a guarantee of service or a binding estimate of conditional curtailment hours from the transmission provider. Progress Energy states that it would be difficult to determine a specific number of hours that firm service is available, given that the industry uses seasonal models. Ameren states that the conditional curtailment hours should be spelled out in the transmission service agreement.

1050. Several commenters state that the transmission provider should provide customers a choice between defined system conditions and conditional curtailment hours.[653] In supplemental comments, EPSA and AWEA state that neither option should be arbitrarily excluded; rather, they argue that transmission providers should consult with each customer in determining the defined conditions that could form the basis of the conditional firm service. EPSA and AWEA propose that conditional firm should be firm during all hours of the year except in those hours in which a defined contingency occurs, and the transmission provider is actually unable to provide service. EPSA and AWEA also propose that the system impact study should describe the reliability contingency and the transmission service agreement should clearly define the contingency.

1051. EPSA and AWEA state that conditional firm should only be curtailed after all non-firm services are curtailed on the same constrained path during the period of the defined contingency. Finally, AWEA and EPSA state that transmission providers must maintain the committed capacity subject to the defined contingency only, reflect capacity commitments for conditional firm service in their ATC calculations, and be prevented from further curtailing conditional firm service due to load growth after the execution of the initial service agreement.

1052. AWEA proposes that if a service agreement specifies conditional curtailment hours, the transmission provider must provide firm service except in the curtailable hours defined in the service agreement and the service must be treated as firm unless the transmission provider is actually required to curtail transactions to meet reliability requirements and all non-firm transactions have been curtailed. Once the transmission provider has reached the annual cap on curtailable hours, AWEA argues the customer's service should convert to traditional firm service for the remainder of that annual period.

1053. Utah Municipals reply that transmission providers should be bound by their calculations of the availability of firm service, even if the firm service is not available year-round.

1054. FirstEnergy and Nevada Companies state that monthly caps, as opposed to annual caps of curtailment hours, would be preferable because they provide more information to the customer and are more appropriate for transmission systems with mostly seasonal constraints. According to Nevada Companies, a curtailment based upon the maximum number of hours per year, without taking into account the specific times or conditions for those curtailments, would be unworkable in the context of a seasonal peak system, such as exists with Nevada Companies.

1055. Several commenters support a variation on conditional firm service that would allow a transmission provider to specify either the transmission facilities/elements that may become constrained or the operating conditions that will result in curtailments of a particular conditional firm service.[654] Many of these commenters propose a defined system condition as the trigger for non-firm curtailment of the service rather than the use of conditional curtailment hours.[655] Entergy and LPPC propose that such curtailments have the same priority as secondary network service. Entergy contends that this service would be superior to the conditional firm service described in the NOPR because it would be more comparable with the service transmission providers make available to network customers and would minimize the risk to other customers who might otherwise bear the cost of inaccurate conditional curtailment hours, as well as disputes between the transmission provider and the transmission customer regarding the number of conditional curtailment hours. Seattle and Santee Cooper suggest that defining the limitations on the service based on operating conditions, with non-binding estimates of hours of curtailment, would lead to more effective and reliable operation of the transmission system that is consistent with regional requirements.

1056. In supplemental comments, Bonneville asserts that the transmission provider should have the option of offering conditional curtailment hours or specified system conditions in order that the transmission provider can make a prudent choice based on available historical system data.

1057. In supplemental comments, TAPS argues that conditional firm service should be limited to 100 hours per year of conditional curtailment, subject to curtailment on the same basis as firm service beyond those hours, and made available to and integrated with network customers. In TAPS view, this would result in a more efficient use of the grid, provide customers sufficient certainty to sign long-term power purchase contracts and promote transmission construction. TAPS also believes that the customer should have the option of expressing the curtailment restriction on the basis of specified system conditions in the 100-hour range.

1058. In its supplemental comments, Entergy suggests that the Commission allow more flexibility between the contracting parties to identify the conditional nature of the service, *i.e.*, the Commission should not prescribe parameters of the conditional period that may ignore real-time conditions on the transmission provider's system that require a curtailment.

1059. EEI, Duke, and PNM–TNMP object, in their supplemental comments, to specifying system conditions or the maximum number of curtailment hours per year, stating that requiring either would be incompatible with current curtailment procedures and unfairly shift risks of curtailment to other firm customers. EEI, Progress Energy and Duke argue that the service should be curtailable during a particular season, month or other defined period to provide more certainty to the transmission customer and the transmission provider as to when the service is subject to curtailment.

1060. With regard to modeling methods for estimating the conditional curtailment hours, EEI asks the Commission not to require the transmission provider to use a specific methodology to evaluate whether it can provide conditional firm service. Bonneville argues that transmission providers need flexibility to modify their ATC methodologies to appropriately model the new service and avoid planning obligations to firm

[653] *E.g.*, Barrick Supplemental, Bonneville Supplemental, BP Energy Supplemental, and EPSA and AWEA Supplemental.

[654] *E.g.*, AWEA, EPSA, Project for Sustainable FERC Energy Policy, Santee Cooper, Seattle, Entergy, and LPPC.

[655] *E.g.*, Santee Cooper, Seattle, Entergy, LPPC, and Nevada Supplemental.

up the conditional curtailment hours of a conditional firm reservation. Nevada Companies suggest that the transmission provider use the appropriate seasonal operating case with updated projections to determine the amount of requested service that can be provided without violating reliability criteria.

1061. Ameren argues that when a transmission provider models system contingency events, the events are not interchangeable with a number of hours. According to Ameren, the two measurements will produce different impacts for the transmission system, and the transmission provider should not be required to make both options available at the customer's option. LPPC and Public Power Council state that transmission providers should not be required to limit the number of curtailments on a monthly or yearly basis because of the inherent unpredictability of future transmission constraints. APPA states that using curtailment based on a specified number of hours will cause the transmission provider to overestimate the number of curtailment hours.

1062. NRECA believes that the Commission should allow for regional flexibility in the determination of the parameters of the service and transmission providers should have maximum flexibility to set conditions that use conservative assumptions (*e.g.*, based on the driest weeks of the year, summer or winter peak period constraints). NRECA believes such service should be conditioned on operating conditions as well as with reference to a number of times of interruption. In contrast, MISO supports the election of a consistent method of curtailment applied to all customers, in order to make the service easier to implement.

1063. Powerex states that conditional firm service should be offered only on paths where curtailment to existing long-term customers is not expected to occur.

Commission Determination

1064. The Commission requires that, when conducting the system impact study for the conditional firm option, the transmission provider shall identify: (1) The specific system condition(s) when conditional curtailment may apply; and (2) the annual number of hours when conditional curtailment may apply. A customer must select either conditions or hours for incorporation into its conditional firm service agreement.

1065. We require the offer of specific system conditions during which conditional curtailment may apply for several reasons. Specified system conditions give certainty to the customer that it will only be conditionally curtailed when forecasted reliability problems actually occur. Transmission providers benefit from this option because they can point to specific constraints on their system and implement a curtailment plan when those transmission elements are constrained. Additionally, designation of specific system conditions may allow for a better fit of the conditional firm service to a specific transmission provider's system. Consider the example of firm service that is not available on a specific system because a transmission line is taken out of service for maintenance about two weeks a year. The designation of this line as the specific condition for conditional firm service would allow the transmission provider to provide firm service without having to worry if the maintenance on the line takes an extra week. The conditional firm customer has fewer concerns about undue discrimination by the transmission provider and could benefit from maintenance on the line that was finished one week early. Additionally, we note that many commenters representing transmission providers and customers support this approach.

1066. We will require specificity of system conditions. Acceptable system conditions include, but are not limited to, designation of limiting transmission elements, such as a transmission line, substation or flowgate. We do not believe, however, that designation of system load levels, standing alone, would qualify as an acceptable system condition. Rather, load levels would have to be linked to a specific constraint or transmission element that is associated with the request for service, *e.g.*, load levels in a constrained load pocket. Otherwise, the system load level would not be specific to the part of the system over which service is requested and, hence, have no necessary relation to the problems, if any, created by the service being requested. Furthermore, because most system loads experience load growth every year, conditional curtailments would necessarily increase over a multi-year conditional firm service term.

1067. We recognize that modeling of the conditional curtailment hours entails difficulties beyond those encountered in modeling ATC. To address these difficulties we are allowing flexibility in determining the number of hours. We clarify that we will not require a standardized method of modeling the conditional curtailment hours. We also note that the Commission's examination of modeling methods in the NOPR was not meant to propose one method over another; rather, it was meant to examine possible ways to determine a number of conditional curtailment hours to encourage dialog on the issue. Additionally, we will allow transmission providers to add a risk factor to their calculation of annual curtailment hours to account for forecasting risks. Further, we note that our adoption of the conditional bridge and reassessment products, detailed above, address modeling difficulties by limiting the number of years that a transmission provider must model in determining both the number of hours and future system conditions. Moreover, we clarify that if the customer selects the annual hourly cap option, the transmission provider has the flexibility to conditionally curtail the customer for any reliability reason during those hours, including but not limited to, the system condition(s) identified in the system impact study. Without this flexibility the hourly cap option and the specific system condition option would be indistinguishable with a cap on the number of hours that the system conditions interruption could occur.

1068. We will require annual caps on the number of hours because calculating an annual cap entails less risk for the transmission provider and its existing firm customers than monthly or seasonal caps. While we will not require monthly or seasonal caps, we encourage transmission providers to offer them if they can overcome modeling barriers because monthly or seasonal caps give more certainty to customers about the particular aspects of their service. Though we allow for flexibility in modeling and determining the number of conditional curtailment hours for a particular service request, we believe that this will have a minimal impact on conditional firm customers. Transmission providers will be allowed to curtail only for reliability purposes and conditional firm customers during conditional curtailment hours will be curtailed only after all point-to-point non-firm customers have been curtailed.

(iii) Conditional Curtailment Priority

Comments

1069. Some commenters agree with the Commission's proposal that conditional firm service should have secondary network curtailment priority during conditional curtailment hours,[656] while others disagree. Bonneville supports the use of the secondary

[656] *E.g.*, Bonneville, AWEA Reply, and EPSA Reply.

network curtailment priority arguing that customers will value the service more with the secondary network priority, thus increasing the viability of conditional firm service as an alternative to transmission upgrades. EPSA and AWEA argue that conditional firm service during conditional curtailment hours should be curtailed after all non-firm uses. In their reply comments, TDU Systems oppose EPSA and AWEA's position, arguing that secondary network service should have at least as high a priority as conditional firm service. In contrast, EEI argues that setting the curtailment priority equal to secondary network service would adversely impact the reliability of firm service by reducing real-time redispatch options and contradict Order No. 888 precedent that provides priority non-firm service only for network customers that pay a load ratio share of system costs.[657] If conditional firm service is implemented, Powerex states that transmission providers should provide data and evidence demonstrating that the rights of existing long-term firm customers will be protected. EEI takes issue with the Commission's proposal to grant conditional firm customers priority non-firm service during conditional curtailment hours because they would pay for long-term use of the grid, stating that all long-term point-to-point customers pay for service on a long-term basis but, unlike network customers, they do not get priority non-firm service.

1070. Commenters address implementation issues related to the Commission's right of first refusal, tagging, tracking, and curtailment priority proposals, as well as other implementation issues implicated in the conditional firm service. Manitoba Hydro, Bonneville and Seattle support the Commission's proposal that conditional firm service would qualify for right of first refusal when firm service becomes available. Several commenters believe that the Commission's proposal with regard to right of first refusal should be refined to allow automatic assignment to conditional firm customers of firm capacity as it becomes available in the short term.[658] Bonneville asserts that prior to implementation of the new service the industry must work with NAESB to develop a communications protocol to either employ automatic assignment or right of first refusal.

1071. Entergy and Exelon state that the standards for implementing transmission loading relief, including the NERC's Interchange Distribution Calculator (IDC), would need modification to allow for curtailment. Specifically, Entergy contends that the Commission should allow time for the IDC to be modified to specify a different curtailment priority for the same transaction depending on the identity of the constraining element. Imperial states that it may take over a year to develop computer software to correctly handle new curtailment priorities during an emergency. Bonneville disagrees and states that conditional firm service does not present unique issues with respect to curtailment and that it would be curtailable during real time like secondary network service.

1072. EEI states that the conditional firm service as currently proposed would conflict with tagging protocols and NERC criteria because there is currently no way to tag service as both firm and non-firm. EEI states that, if conditional firm service is subject to curtailment during a specific period, the tag can identify those periods and curtailments will be implemented in conditional periods and non-conditional periods in accordance with those tags. However, if conditional service is curtailable in a certain number of hours, or when specific conditions occur, the tag cannot be rewritten in a way that will provide for curtailment without personal involvement of balancing authority operators, which could lead to increased curtailments of firm transmission customers.

1073. Xcel states that limiting curtailments to a specified number of hours per year could result in conditional firm service having greater value than firm, while strictly adhering to a maximum number of curtailment hours could potentially conflict with the reliability standards in section 215 of the FPA. NRECA argues that conditional firm service should be subject to *pro rata* curtailment with all other firm users during non-conditional times.

Commission Determination

1074. We adopt a secondary network curtailment priority to apply for the hours or specific system conditions when conditional firm service is conditional. During non-conditional periods, conditional firm service is subject to *pro rata* curtailment consistent with curtailment of other long-term firm service. Thus, secondary network service and conditional firm service when it is conditional will share the same curtailment priority. Also, there is no conflict with reliability standards because conditional firm service will be subject to *pro rata* curtailment with all other firm uses of the system once conditional curtailment hours, if that is the option selected, are exhausted.

1075. The secondary network curtailment priority is appropriate because the customer is paying the long-term firm point-to-point rate and thus should receive the highest non-firm curtailment priority during the conditional curtailment hours or during specified system conditions. Adoption of this curtailment priority overcomes what could otherwise be significant implementation hurdles. It allows for implementation of the service without changes to existing NERC TLR practices. NERC and members of the industry need not undertake the time-consuming and expensive process of establishing a new curtailment priority that is between firm and non-firm service as some commenters requested. Use of this curtailment priority also avoids attendant decisions relating to the method of curtailment that should apply, *i.e., pro rata* or transactional curtailment, for a quasi-firm curtailment priority. It is also consistent with existing interruption provisions of the *pro forma* OATT which provide that secondary service cannot be interrupted for economic reasons.[659] This is consistent with our determination that conditional firm service when it is conditional is curtailable only to maintain reliable operation of the transmission system.

1076. We reject EEI's argument that the curtailment priority for conditional firm service is inconsistent with Commission precedent regarding priority non-firm service only for network customers. EEI's argument is inapposite. Long-term firm point-to-point customers taking fully firm service without the conditional firm option do not need access to priority non-firm service as EEI suggests. They have assurance that their service will not be interrupted for economic reasons and will only be curtailed on a comparable basis with network service. This would not be the case for conditional firm customers. We also find that EEI has failed to explain the connection between the conditional firm transmission service and the availability of reliability redispatch options, *i.e.*, generators on its system that can ramp up or down in response to a curtailment. We reject Powerex's request that transmission providers be required to show that existing long-term rights are protected. Each addition of a new long-term firm transaction impacts

[657] *Citing* Order No. 888 at 31,750.

[658] *E.g.*, EEI, EPSA, TranServ, Bonneville, Constellation and Seattle Reply.

[659] *See pro forma* OATT section 14.7.

the rights of existing firm customers to some extent.

1077. We disagree with commenters' suggestion that the NERC IDC must be changed to accommodate conditional firm service. We reiterate that we are not creating a new curtailment priority in this Final Rule. We also disagree that new tags that combine a firm and non-firm priority must be developed in order to implement the conditional firm option. The curtailment priority in a tag can be changed ahead of the operating hour based on a near-term forecast of system conditions.[660] We are cognizant that daily and hourly operations to change the tags for conditional firm customers likely involve the need for control room coordination and development of an appropriate tracking process. As the Commission described in the NOPR, new tracking and tagging business practices for this service must be developed by each transmission provider. Thus, we are allowing a sufficient period for the development of these business practices, *i.e.*, 180 days from the date of publication of this Final Rule in the **Federal Register**. As directed above, transmission providers must coordinate with other transmission providers in their regions to develop these tracking and tagging business practices.

1078. Finally, we address requests to allow for automatic assignment of short-term firm point-to-point service to conditional firm customers. We agree that transmission providers must take into account the conditional firm service in evaluating the availability of short-term firm service. Because conditional firm is a long-term firm use of the system, it should not be interrupted prior to short-term firm service. However, short-term firm service reserved prior to the reservation of conditional firm service should maintain priority over conditional firm service in the periods when conditional firm service is conditional, *i.e.*, when specified system conditions exist or conditional curtailment hours apply. Because the assignment proposal meets both of these objectives, we direct transmission providers to assign short-term firm service to conditional firm customers as the service becomes available. Accordingly, we direct transmission providers to work with NAESB to develop the appropriate communications protocols to implement this attribute of conditional firm service. Transmission providers need not implement this requirement until NAESB develops appropriate communications protocols.

(iv) Rollover Rights

Comments

1079. Several commenters support the Commission's proposal that conditional firm service would qualify for rollover rights.[661] Manitoba Hydro, Bonneville and Seattle state that rollover rights are appropriate where the transmission provider does not have an obligation to plan for service to the conditional firm customer during the conditional curtailment hours. Bonneville adds that, in rolling over conditional firm service, the transmission service agreement should allow for no more than the same number of conditional curtailment hours than in the original service agreement and provide for fewer hours of curtailment if system conditions provide for more firm service. If conditional firm service is used as an interim product until transmission is built, APPA contends that rollover rights would be appropriate.

1080. Others argue that rollover rights for conditional firm service are inappropriate.[662] These commenters do not support the granting of rollover rights, nor do they support the designation of conditional firm service as long-term service. In order to accommodate conditional firm rollover rights, FirstEnergy contends that the transmission provider would be required to model a number of off-peak load flow cases and provide system reinforcements. Ameren states that the number of hours that the service will be available at some future date after the contract expires will not be known at the time the initial contract is executed. EEI adds that estimating conditional curtailment hours for 10 years of service is an impossible task. MISO states that rollover rights would add more complexity to the AFC/ATC calculation process and competition queues. Entergy and EEI state that, while subsequent firm transmission service should not be placed ahead of the conditional firm service, it is appropriate at the time of a rollover request, and perhaps more frequently, to allow the transmission provider to update the conditional firm service parameters in order to take into account load growth and changes in load for prior services.

Commission Determination

1081. The Commission finds that rollover rights are appropriate for point-to-point service that is provided using planning redispatch or conditional firm options and would otherwise be eligible for rollover rights. The following discussion addresses only rollover rights for service that is paired with a transmission provider's biennial reassessment right. While the Commission agrees with commenters that subsequent firm transmission service requests should not be placed ahead of the conditional firm service, we note above our concerns with the modeling requirements and reliability impacts of an ongoing service that relies upon unchanging curtailment conditions or redispatch requirements. The biennial assessment right, discussed above, addresses the concern expressed by EEI that transmission providers cannot accurately determine conditional curtailment hours or estimate redispatch costs for a ten-year service. The biennial review in conjunction with rollover rights allows the transmission provider to update the parameters of the service in order to maintain reliable operations and allows customers to keep their place in the queue ahead of other customers seeking conditional firm, planning redispatch options, or other firm services.

1082. Rollover rights for the reassessment product can provide significant value to the conditional firm customer. A conditional firm customer opting to roll over will retain priority claim to the portion of its service that is firm. For example, if a five-year conditional firm service initially has a 100-hour annual cap on curtailments, but the cap is later reassessed at 150 hours, the rollover right would continue to give the customer first call on all but the 150 hours as against all other subsequent requests for firm service.

1083. We note that a customer taking conditional firm or planning redispatch options as part of a five-year point-to-point service must declare its intent to roll the service over in the fourth year of service, coincident with the second biennial review. Thus, we task transmission providers and customers, in negotiating their service agreement, with coordinating the timing of the biennial review with the deadline for declaring rollover intent. Specifically, customers deciding whether to renew their service should have information on additional conditions on the service or additional estimated redispatch costs

[660] For example, in the Eastern Interconnection, tags can be changed up to 35 minutes before the hour in which a TLR event is scheduled. *See* NERC Standard IRO–006–3, *Transmission Loading Relief Procedures—Eastern Interconnection*, section 6.2 (Communications and Timing Requirements) at 23–25 (August 2, 2006).

[661] *E.g.*, AWEA, EPSA, Manitoba Hydro, Bonneville, TranServ, Seattle, and Utah Municipals Reply.

[662] *E.g.*, EEI, FirstEnergy, Ameren, SPP, and TDU Systems Reply.

at least 30 days prior to the relevant rollover deadline.

1084. Additionally, because the biennial review provides the transmission provider with the ability to plan for and maintain system reliability, we will not allow the rollover right to infringe upon this review. Thus, we direct that the transmission provider has a right to review the conditions or redispatch requirements at the end of the first year of a service that has been rolled over, *i.e.*, year six of service, as consistent with a biennial review of service.[663]

(v) Use of Conditional Firm Options in Designating Network Resources

Comments

1085. Several commenters state that the Commission should not modify current OATT requirements for designating network resources to include resources delivered using conditional firm service; otherwise, reliability would be threatened because network customers could lean on the system during conditional periods.[664] They oppose allowing a resource taking conditional firm service to qualify as a network resource when the associated resource is imported by a network customer from an adjacent system. EEI and Duke agree with the Commission's NOPR proposal that conditional firm service should not be available to network customers and further assert that a product that includes a non-firm portion is inappropriate for a load-following service like network service. EEI asserts that because the Commission requires that network resources be deliverable on a non-curtailable basis, resources using conditional firm service cannot be designated as a network resource until the maximum conditional curtailment hours have been reached. EEI and Duke contend that establishing a defined period of curtailment for conditional firm service, either seasonal, monthly, or specific dates, eliminates issues with respect to the designation of network resources because a resource using conditional firm service would be eligible for designation for the part of the year when the service was defined as firm. In its reply comments, Duke states that it cannot reliably operate its system if it is required to serve unplanned load when a network resource is undeliverable due to curtailment of conditional firm service.

1086. Other commenters assert that the Commission should create an exception to allow designation of network resources that use conditional firm service.[665] AWEA adds that resources should not lose their designation when transactions are curtailed pursuant to conditional firm service because this is not the way similar resources with special protection systems are treated. Several commenters state that conditional firm service should qualify as a network resource when the associated resource is imported by a network customer.[666] BP Energy adds that more coordination between the two systems with respect to specifying the set of conditions or specific set of hours is required.

1087. Some commenters state that conditional firm service should be made available to network customers because conditional firm service may trump the provision or scheduling of secondary network service and because network customers should have service that is at a minimum equivalent with point-to-point service.[667] These commenters suggest that the Commission could permit network customers to designate a conditional network resource that would be a firm resource for the hours when a comparable conditional firm point-to-point service is firm. In supplemental comments, NRECA and TAPS argue that ''on-system'' LSEs should be allowed to designate a network resource where transmission is fully firm for all but the limited time each year, *e.g.*, to 100 hours or less, and ''off-system'' LSEs should be allowed to treat a network resource supported by conditional firm service as a resource on the host system where it takes network service. NRECA believes that if the criteria for both network service resource designations and for the proposed conditional firm service are based on the physical, engineering characteristics of the transmission system, the network customer should be able to designate the resource as deliverable to load on a non-curtailable basis, except for the specified conditions.

1088. In its reply comments, Bonneville states that since secondary network service cannot be purchased on a long-term basis, the Commission should evaluate whether the design and implementation challenges of creating a conditional firm service for network customers can be overcome. Bonneville also states that other options such as seasonal firm and long-term reservation of secondary network service should be explored in order to allow network customers similar access to monthly ATC.

1089. Nevada Companies state that network customers have load service obligations and should always have unconditional firm service, without exception. However, Nevada Companies state that network customers could benefit from a service similar to conditional firm service. According to Nevada Companies, if a network customer desires to deliver its resources to a point of receipt that is not available all seasons of the year, it could procure firm transmission capacity that is available on a seasonal basis for the delivery of a network resource.

1090. Some commenters state that network customers should be permitted to designate as network resources third party power supplies that are supported by the supplier's conditional firm reservation.[668] In supplemental comments, Xcel states that it does not oppose allowing conditional firm to qualify as a network resource, but it should be clear that the service is an exception to the otherwise ''firm is firm'' policy that requires all firm users to be curtailed pro-rata.

Commission Determination

1091. The Commission will allow conditional firm point-to-point service to qualify as firm service that supports the designation of network resources imported from other control areas. As we explain in more detail in section V.D.6, the Commission has longstanding limitations on network resources. Network resources cannot be interrupted for economic reasons and third-party transmission arrangements to deliver the resource to the network must be non-interruptible.[669] EEI is incorrect that, under our precedent, a resource must be ''noncurtailable'' to qualify as a network resource under the OATT. All resources are ''curtailable''—*e.g.*, if a unit trips off line, the resource is, by definition, curtailed. Network resources may also be unavailable due to other reasons besides an unplanned unit outage, such as unplanned transmission outages or environmental restrictions. It is appropriate to allow conditional firm service to support the

[663] Such a review would occur in the first year of a rolled over service if the initial service term was for five years.

[664] *E.g.*, Entergy Supplemental, Southern Supplemental, MISO Supplemental, Community Power Alliance Supplemental, and Powerex Supplemental.

[665] *E.g.*, AWEA, EPSA, TAPS, APPA, Utah Municipals Reply, and Barrick Reply.

[666] *E.g.*, Bonneville Supplemental, TDU Systems Supplemental, PPL Supplemental, and BP Energy Supplemental.

[667] *E.g.*, NRECA, TDU Systems, TAPS, and Utah Municipals Reply.

[668] *E.g.*, APPA Supplemental, EPSA and AWEA Supplemental.

[669] *Wisconsin Public Power Inc.* v. *Wisconsin Public Service Corp.*, 84 FERC ¶ 61,120 at 61,660 (1998) (*WPPI*).

designation of network resources because the conditional firm option only affects the transmission of the resource to the network, not the interruptibility of the generating resource itself. Conditional firm service satisfies the Commission's requirement for the delivery of the resource to the network to be non-interruptible because such transmission service is curtailable only for specific reliability reasons, not economic reasons.

1092. We decline, however, to adopt the conditional firm option for network service. Commenters argue that conditional firm network service should be made available to prevent conditional firm point-to-point service from ''trumping'' the scheduling of secondary network service and to ensure that network service is at a minimum equivalent to point-to-point service. Concerns regarding conditional firm point-to-point service ''trumping'' secondary network service would not be resolved by creating conditional firm network service. The ''as available'' nature of secondary network service will still permit all firm uses of the system, including conditional firm service, to have a higher reservation priority than secondary network service. Creating a conditional firm network service would not change that reservation priority.

1093. Others argue that conditional firm network service should be required in order to ensure that network service is equivalent to point-to-point service. As noted above, however, the two services are not precisely the same, nor were they intended to be identical. In Order No. 888, the Commission attempted to strike a balance between competing interests in designing network and point-to-point transmission services, each service with its own costs and benefits. It is therefore appropriate that we consider the need for conditional firm service in each context. While we conclude that implementation of conditional firm network service is not necessary to remedy undue discrimination at this time, we note that allowing conditional firm point-to-point service will nonetheless provide substantial benefits to network customers by allowing the designation of network resources delivered to the network from other control areas using conditional firm point-to-point service. Conditional firm point-to-point service will thereby allow network customers to access new alternative power sources. Transmission providers are free to make a filing under FPA section 205 proposing conditional firm network service.

1094. Finally, in light of our conclusions above that conditional firm service satisfies the Commission's requirements for designating network resources because the delivery of the resource to the network is not interruptible for economic reasons, we do not need to adopt a seasonal, monthly or periodic method for determining the conditions under which conditional service may be curtailed as suggested by EEI and others.

b. Proposals for Transparent Redispatch

NOPR Proposal

1095. In the NOPR, the Commission explained that the major focus of this rulemaking was to strengthen the *pro forma* OATT in order to remedy undue discrimination rather than create new market structures. The Commission stated its intention to retain the use of an OATT to facilitate the development of competitive wholesale markets by reducing barriers to entry through the control of transmission assets, not impose any particular market structure on the industry.

Comments

1096. Several commenters argue that the Commission should expand the planning redispatch requirements of the *pro forma* OATT to incorporate third party provision of redispatch and bidding protocols.[670] In reply comments, Transparent Dispatch Advocates submitted a proposal that, among other things, would require transmission providers to (1) post the real-time cost estimate of providing redispatch service from their resources at congested locations, (2) accept offers from third parties to provide redispatch service, and (3) provide real-time redispatch to resolve transmission constraints. Transparent Dispatch Advocates argue that their proposal is consistent with the scope of the rulemaking because it would not require the adoption of LMP markets or other standardization; rather, it would simply provide cost visibility and proper cost assignment of the dispatch decisions made by transmission providers.

1097. In a notice issued on November 15, 2006, the Commission sought further comment on the TDA proposal. The Commission asked, inter alia, about implementation impediments and confidentiality issues related to posting redispatch costs, whether the TDA proposal was required to remedy undue discrimination, and whether third party participation in redispatch would require market mechanisms.

Commission Determination

1098. The Commission addresses below two distinct parts of the TDA proposal: (1) Expansion of transmission provider's real-time reliability redispatch obligation as well as inclusion of third-party resources in provision of redispatch and (2) posting of real-time redispatch costs or prices.[671] The Commission has carefully considered both the TDA proposal and the comments respecting it. We agree with many of the public policy goals articulated by Transparent Dispatch Advocates, such as increasing the transparency of information and increasing the efficient use of existing infrastructure. However, we also agree with many of the commenters that certain aspects of the TDA proposal are unclear and, depending on its interpretation, may require the creation of new services under the *pro forma* OATT or new market structures. We are particularly cognizant of the arguments of customer groups such as APPA, NRECA and TAPS that the TDA proposal may be difficult to implement, contentious, and may not provide significant benefits to customers. These customers also are concerned that it may detract from other reforms considered in this proceeding that they believe provide greater benefits, such as transmission planning reform.

1099. After considering the views of all the parties, the Commission has sought to strike a reasonable balance between the positions of the commenters. On the one hand, we adopt certain reforms that will provide additional information regarding redispatch costs in a manner that benefits consumers. On the other hand, we will not adopt the portions of the TDA proposal that would require the creation of new services under the *pro forma* OATT or new market structures. We do not believe that such fundamental changes are necessary or appropriate at this time, nor do we have an adequate record upon which to adopt them.

1100. Specifically, the Commission declines to adopt the TDA proposal to expand transmission providers' real-time reliability redispatch obligations and incorporate third party bids into redispatch. As discussed in detail above, transmission providers will continue to have an obligation to

[670] *See* section V.C.1 of this Final Rule for a discussion of comments regarding independent dispatch and spot market development.

[671] Transparent Dispatch Advocates' proposal for mandatory coordination agreements between transmission providers for provision of redispatch service is addressed in section V.C.1 of this Final Rule.

perform reliability redispatch for network customers and provide the planning redispatch described above for point-to-point customers. Transmission providers will not be required, as Transparent Dispatch Advocates request, to incorporate third party resources when providing reliability redispatch or evaluating planning redispatch options for point-to-point or network transmission service. We will, however, institute a posting requirement so that the actual costs of redispatch under existing and future redispatch agreements is made transparent to potential customers. While we will not require posting of a real-time estimate of redispatch prices as proposed by Transparent Dispatch Advocates, the Commission concludes that the posting requirement required herein will provide important information regarding the costs of redispatch without revealing confidential information that might harm existing markets.

(1) Expansion of Reliability Redispatch Obligation and Inclusion of Third Party Resources

Comments

1101. In reply comments filed September 20, 2006, Transparent Dispatch Advocates argue that the Commission must bring transparency to the dispatch function to make redispatch effective and fair and to thereby remedy the potential for discriminatory provision of transmission service. Transparent Dispatch Advocates assert that the Commission should require each transmission provider to publish a ''dynamic real-time value of what it would charge to provide redispatch service at specified congestion locations within the transmission provider's system and at specified flowgates at the border of the transmission provider's system.'' [672] Transparent Dispatch Advocates contend that the publication of this data would: Allow customers to assess available real-time redispatch options; allow customers to access redispatch at actual costs; allow customers to predict with reasonable certainty the costs of redispatch; allow all resource owners to voluntarily offer redispatch solutions and be properly compensated for their efforts; and over time, support long-term transmission service.

1102. In reply comments, Transparent Dispatch Advocates further request adoption of rules that would either require the transmission provider to account for independent, third party resources in its control area in establishing redispatch costs, or allow independent resources to post real-time, cost-based price and quantity bids for redispatch plus the resource's impact on the constraint on the transmission provider's OASIS. Transparent Dispatch Advocates state that the published redispatch values would be cost-based in non-market environments.

1103. On November 3, 2006, a summary of, and frequently asked questions regarding, the TDA proposal (TDA Summary) was attached to comments filed by San Diego G&E in response to the October 12 Technical Conference and in support of the TDA proposal. In the TDA Summary, Transparent Dispatch Advocates assert that the Commission need only revise the existing redispatch provisions of the *pro forma* OATT to require posting by the transmission providers of the nature of congestion at pre-designated flowgates and data concerning the response required to relieve congestion. Additionally, the TDA Summary states that the transmission provider would have no obligation to provide for real-time redispatch from its own or affiliated generation; rather, all generators wishing to provide redispatch could volunteer to submit bids. Transparent Dispatch Advocates state that these bids could be either market or cost based depending on whether the bidder has market-based rates within the control area. The transmission provider would be obligated to evaluate the bids, publish the price for redispatch, and call on generators to provide the requested redispatch in real time. Transparent Dispatch Advocates suggest that transmission providers calculate the price for redispatch by taking the difference between bids received by those generators that the transmission provider would call upon to increase output (*i.e.*, to redispatch) and the costs the transmission provider otherwise would have paid the generator whose output is lowered to relieve the constraint. Transparent Dispatch Advocates contend that their proposal differs from LMP markets because, while LMP sets system-wide clearing prices, their transparent redispatch proposal would apply only at selected flowgates and only with respect to those transacting at those flowgates.

1104. On December 15, 2006, in supplemental comments filed in response to the Commission's November 15 Notice asking for comment on the TDA proposal, Transparent Dispatch Advocates sought to clarify their proposal. Transparent Dispatch Advocates propose that the Commission impose upon transmission providers an obligation to do the following: Provide reliability redispatch to point-to-point customers in real-time for comparable treatment to that currently provided to network customers and native load; consider their own resources, network resources, and offers from non-network resources in providing least cost redispatch in real-time; and, publish real-time information about the cost of redispatch (including the prices submitted by non-network resources) on its OASIS site on a frequent and timely basis. In their supplemental comments, Transparent Dispatch Advocates propose a different method for calculating redispatch prices using the difference between the cost of the generation raised and the pre-redispatch transmission provider's system-wide marginal cost (*e.g.*, system lambda). Transparent Dispatch Advocates further propose that point-to-point redispatch customers taking this service would not be subject to curtailment along with other firm customers in accordance with the current OATT curtailment rules. Transparent Dispatch Advocates argue that their modified proposal would facilitate comparable access to redispatch service and ensure that the existing redispatch provisions of the OATT can be made effective.

1105. Several parties offer comments in support of the TDA redispatch proposal.[673] Constellation encourages the Commission to fully consider the TDA proposal in the appropriate context, whether in this docket or in a separate proceeding. California Commission states that a movement of OATT policy in the direction implied by the TDA proposal is necessary to improve efficiency of generation and transmission investment. BP Energy believes that a redispatch mechanism is necessary to minimize aggregate consumer costs and make redispatch equally available to all participants. PPM supports the TDA proposal noting that it would provide sufficient cost certainty for both the transmission provider and the customer and make more efficient use of the existing grid without impacting reliability. Although it opposed the proposal initially, MISO states that it now cautiously supports the TDA redispatch proposal, provided that RTOs do not bear an inappropriate share of costs to modify information technology systems.

[672] Transparent Dispatch Advocates Reply at 5.

[673] *E.g.*, EPSA and AWEA Supplemental, Constellation Supplemental, California Commission Supplemental, PPL Supplemental, BP Energy Supplemental, PPM, and San Diego G&E.

1106. Many commenters oppose the TDA proposal stating that the record in this proceeding does not warrant implementing such a complex and uncertain proposal which imposes significant risks, costs and burdens on transmission providers and their native load customers.[674] Public Power Council, Southern, and NRECA do not believe that the Commission should adopt the TDA proposal without an analysis of costs and benefits and note that no party has provided any such analysis. OG&E and Public Power Council state that the costs of congestion likely vary greatly by region and argue that Transparent Dispatch Advocates have provided no evidence that their industry-wide solution solves potential regional redispatch problems.

1107. Several state commissions oppose adoption of the TDA proposal or urge the Commission to impose significant conditions on the proposal to protect retail customers.[675] SEARUC, Alabama Commission, Florida Commission, Georgia Commission, North Carolina Commission and South Carolina Regulatory Staff express concern that the TDA proposal would make competitively sensitive information available to the public on an inconsistent basis, compel the provision of additional services that risk increasing retail costs, harm reliable service to retail ratepayers that state commissions are obligated by state laws to protect, impose administrative difficulties and excessive implementation costs, and compel states or regions to change current practices or market structures in contradiction of EPAct 2005. SEARUC asks the Commission to make clear that implementation of a proposal targeted at enhancing transparency will not result in a federally imposed change in economic dispatch practices or lessen the amount of firm capacity available for service to native load customers. SEARUC also expresses concern regarding the imposition of incremental costs upon retail ratepayers without prior state approval or the implementation of any type of process or organization that has not been approved by state regulators as cost effective for retail customers. SEARUC opposes the mandatory use of LMP or LMP-like pricing, congestion management approach or organized wholesale market structure without prior state endorsement; and the mandatory posting of competitively sensitive, generation plant-specific costs or price information.

1108. Georgia Commission states that radical restructuring is not necessary to achieve the goals stated by the Commission in the NOPR. Alabama Commission, Georgia Commission and South Carolina Regulatory Staff state that analyses associated with potential implementation of new market structures in the Southeast have demonstrated that the implementation costs associated with such structures vastly outweigh the benefits. North Carolina Commission argues that the TDA proposal fails to comply with the Commission's directive in the NOI. In its view, the Commission intended to focus in this proceeding on specific problems that continue to exist and targeted remedies.

1109. North Carolina Commission states that the Transparent Dispatch Advocates' reply comments incorrectly equate the use of redispatch for economic purposes pursuant to 13.5 of the *pro forma* OATT with its use for reliability purposes. North Carolina Commission maintains that these services are not comparable, and thus the use of redispatch for reliability purposes does not justify requiring a transmission provider to provide it for economic purposes. North Carolina Commission asserts that implementation of the TDA proposal would result in substantial benefits accruing to PJM without commensurate benefits to non-RTO areas. North Carolina Commission, Southwest Utilities and Southern argue that the costs of implementing the proposal are not justified by any potential efficiency benefits and thus there is a compelling reason to reject the TDA proposal.

1110. Several parties argue that the TDA proposal represents a move toward Standard Market Design (SMD).[676] Alabama Commission, Georgia Commission and North Carolina Commission submit that the TDA proposal shares characteristics with the centralized dispatch and LMP proposals advanced in the SMD proceeding and thus conflict with state commission jurisdiction in much the same manner as the SMD proposal. Georgia Commission and others assert that the only difference between the SMD proposal and TDA proposal is that the TDA proposal would require transmission providers, but not third party merchants, to make their costs transparent.[677] NRECA believes that a real-time pricing scheme based on some value other than actual costs constitutes the creation of a new product and an organized, bid-based market in regions that have not adopted such market structures. NRECA contends that it would be politically unacceptable to reform the OATT in a manner that necessitates the formation of regional bid-based markets in non-RTO areas.

1111. In contrast, California Commission supports the TDA proposal to the effect that transmission providers should be required to post redispatch cost information and to provide real-time redispatch. In supplemental comments, California Commission asserts that this effort is needed to prevent undue discrimination, for improved efficiency of generation and transmission investment and to improve the efficiency, transparency and openness of redispatch, and transmission access generally.

1112. Some commenters argue that the TDA proposal is necessary to remedy undue discrimination.[678] Others disagree.[679] Transparent Dispatch Advocates contend that making real-time economic dispatch available to ''non-network transmission customers'' is necessary to remedy undue discrimination against those customers as compared with network customers. In their supplemental comments, EPSA and AWEA state that the TDA proposal is necessary to remedy the same undue discrimination targeted by the NOPR proposal pertaining to planning redispatch service. PPL suggests that the TDA proposal may permit transmission customers to benefit from redispatch, which transmission owners in non-RTO

[674] *E.g.*, LPPC Supplemental, Community Power Alliance Supplemental, Public Power Council Supplemental, Pacific Coast Parties Supplemental, EEI Supplemental, Duke Supplemental, Southern Supplemental, Southwest Utilities Supplemental, South Carolina E&G Supplemental, Ameren Supplemental, Alabama Commission Supplemental, Florida Commission Supplemental, Georgia Commission Supplemental, North Carolina Commission Supplemental, South Carolina Regulatory Staff, and SEARUC Supplemental.

[675] *E.g.*, Alabama Commission Supplemental, Florida Commission Supplemental, Georgia Commission Supplemental, North Carolina Commission Supplemental, South Carolina Regulatory Staff, and SEARUC Supplemental.

[676] Commenters reference a proposal in a proceeding terminated by the Commission. *See Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design,* 67 FR 55454 (Aug. 29, 2002), FERC Stats. & Regs. ¶ 32,563 (2003), *terminated by,* 112 FERC ¶ 61, 073 (2005).

[677] *E.g.*, Community Power Alliance Supplemental, and Entergy Supplemental.

[678] EPSA and AWEA Supplemental, BP Energy Supplemental, California Commission Supplemental.

[679] *E.g.,* LPPC Supplemental, Community Power Alliance Supplemental, Public Power Council Supplemental, Pacific Coast Parties Supplemental, EEI Supplemental, Duke Supplemental, South Carolina E&G Supplemental, Ameren Supplemental, North Carolina Commission Supplemental, South Carolina Regulatory Staff Supplemental, and North Carolina Commission Supplemental.

areas now employ to benefit themselves or their native load customers.

1113. A number of commenters assert that neither the record nor Transparent Dispatch Advocates present evidence of discriminatory treatment of transmission customers with regard to transparent redispatch.[680] South Carolina E&G asserts that implementation of the TDA proposal should not be unjustifiably forced onto individual transmission providers given that there is no demonstration that there is a problem. MidAmerican and Progress Energy and others argue that unsupported assertions of undue discrimination are insufficient to support the TDA proposal. These commenters argue that pursuant to the recent *National Fuel* decision, the courts would likely require the Commission to overcome substantial hurdles in order to adopt the TDA proposal based on theoretical assertions of undue discrimination.[681] These commenters contend that the *National Fuel* case would likely require the Commission to demonstrate how potential undue discrimination justifies a costly redispatch proposal, why section 206 rights are insufficient to ensure redispatch is comparably provided, and why the comparability findings of Order No. 888 are no longer sufficient.

1114. In response to assertions that utilities routinely redispatch to meet electric load, LPPC argues that there is nothing discriminatory about a vertically integrated utility's use of its own nonjurisdictional generation to support bundled sales service. LPPC states that the use of generation first to serve native load has been the fundamental operating principal for jurisdictional and nonjurisdictional utilities for decades, and certainly under Order No. 888. LPPC concludes that this is not a problem calling for Commission attention. In response to assertions that TLRs are discriminatory, Duke notes that neither the Transparent Dispatch Advocates nor any other commenter has provided an analysis of the scope, location and magnitude of the TLR problem.

[680] *E.g.,* LPPC Supplemental, Community Power Alliance Supplemental, Public Power Council Supplemental, Pacific Coast Parties Supplemental, EEI Supplemental, Duke Supplemental, MidAmerican and Progress Energy Supplemental, South Carolina E&G Supplemental, Ameren Supplemental, North Carolina Commission Supplemental, North Carolina Commission Staff Supplemental, and North Carolina Commission Supplemental.

[681] *E.g.,* Entergy Supplemental, LPPC Supplemental, Public Power Council Supplemental, and OG&E Supplemental.

1115. Many commenters contend that the TDA proposal is ambiguous, insufficiently developed or marked by inconsistencies.[682] Pacific Coast Parties argue that the TDA proposal is too sweeping and contains too many uncertainties to allow for meaningful comment. Southwest Utilities believe that it would be premature for the Commission to adopt the TDA proposal without further development, comment, discussion and input from affected electric industry stakeholders. PPL and Xcel believes that the Commission needs to better define the proposed new service and allow comment on the service before detailed tariff language is developed to implement this proposed new service. Public Power Council contends that, although the proposal appears to seek only the posting of information, in reality, Transparent Dispatch Advocates ask that the Commission require reciprocal redispatch coordination. Public Power Council also argues that the TDA proposal is silent or ambiguous concerning critical issues associated with implementation; the proposal fails to explain the ''cost'' at which transmission providers would offer redispatch or the price, terms, and conditions of such a transaction.

1116. Several parties refer to seeming discrepancies between Transparent Dispatch Advocates' explanations of the proposal and question whether the TDA proposal entails cost-based or market-based bidding.[683] APPA notes that Transparent Dispatch Advocates state in reply comments that effective redispatch service must reflect actual costs. APPA adds that the TDA Summary, in contrast, provides that any generator with market-based rate authority in the transmission provider's control area could charge a market-based price for generation offered for redispatch service. LPPC, TDU Systems, TAPS, APPA and NRECA express concern about allowing redispatch providers to bid under market-based rate authority. These commenters argue that reliance on existing market-based rate authority to support redispatch offers no protection against the exercise of market power, given the high concentration of transmission provider-owned generation within its control area. If the Commission adopts the TDA proposal, APPA asserts that the Commission should limit all sellers of generation used for redispatch service to cost-based bids and require all parties to provide cost information.

[682] *E.g.,* Pacific Coast Parties Supplemental, Southwest Utilities Supplemental, Entergy Supplemental, EEI Supplemental, PPL Supplemental, Public Power Council Supplemental, Florida Commission Supplemental, SEARUC Supplemental, Progress Energy and MidAmerican Supplemental, APPA Supplemental, NRECA Supplemental, and TAPS Supplemental.

[683] *E.g.,* Progress Energy and MidAmerican Supplemental, APPA Supplemental, NRECA Supplemental, and TAPS Supplemental.

1117. In supplemental comments, EEI and Public Power Council assert that the Commission in seeking comment on the TDA proposal has not proposed a rule with sufficient clarity to allow meaningful comment and, therefore, it would be inappropriate to adopt the TDA proposal based on this proceeding's record. Pacific Coast Parties add that the Commission cannot adopt the TDA proposal based on the sparse record in this proceeding. MidAmerican and Progress Energy contend that the Commission's notice here does not satisfy Administrative Procedure Act requirements for public notice and comments on the TDA proposal. In their view, the Commission must initiate a separate rulemaking proceeding to evaluate the TDA proposal.

1118. Progress Energy and MidAmerican assert that, under the current *pro forma* OATT, redispatch is based on a ''careful'' evaluation of the reliability and cost impacts of using redispatch on a long-term basis and thus the transmission provider is able to serve transmission customers and wholesale load-serving obligations at least cost. In their view, the transmission provider's retail and wholesale customers would absorb the costs to serve transmission customers that obtain the forced real-time redispatch under the TDA proposal.

1119. Community Power Alliance, North Carolina Commission, Progress Energy and MidAmerican contend that native load customers would be harmed by a requirement that transmission providers sell their excess generation to redispatch customers. They state that such a requirement would prevent or reduce the sale of generation in competitive markets and that these market sales would otherwise reduce costs to native load customers. Moreover, where the transmission provider is required to redispatch its own generation, Progress Energy and MidAmerican argue that Transparent Dispatch Advocates' proposed redispatch would either use more expensive units or cause the transmission providers to lose the opportunity to make higher valued sales, which also increases costs for native load customers.

1120. In supplemental comments, E.ON, Progress Energy and MidAmerican assert that some generators face limits with regard to the

amount of time that they are allowed to operate due to air emissions caps and maintenance schedules. They contend that the TDA proposal could cause allowable run time to be ''used up'' prior to the time that the generator has fulfilled its planned native load obligation, thus requiring that the transmission provider resort to alternative, likely more expensive, power supplies for these obligations.

1121. Several parties assert that Transparent Dispatch Advocates' proposal to substitute redispatch for transmission upgrades will depress transmission investment.[684] LPPC argues that Transparent Dispatch Advocates' proposal conflicts with the Commission's policy of promoting transmission infrastructure development. NRECA states that, to the extent that redispatch is required to fulfill long-term point-to-point service on a particular transmission provider's system, such providers have failed to meet their obligations under the existing OATT to plan and expand the system for those transmission customers' long-term needs. NRECA envisions redispatch customers potentially requesting ''ever more convoluted'' dispatch rules in order to avoid transmission upgrades. NRECA prefers better enforcement of section 15.4 of the OATT in conjunction with a more open and inclusive planning process. TAPS argues that transmission providers will profit from market-based prices for redispatch and will be discouraged from transmission expansion. TAPS contends that PJM has conceded that LMP signals have proven insufficient to create a robust grid. In TAPS view, this counters Transparent Dispatch Advocates' claims that their proposal will reveal the value of transmission upgrades and encourage investment.

1122. Several commenters submit that the TDA proposal raises Standards of Conduct issues.[685] They argue that requiring the TDA proposal would complicate if not undermine the functional separation and information sharing policies of the Standards of Conduct because the transmission function would be performing merchant, or at least merchant-related, functions. According to Community Power Alliance, the requirement that transmission providers allow merchant generators to offer to sell generation to alleviate constraints in order that other customers' transactions could flow would violate Standards of Conduct.

1123. TAPS argues that accurately forecasting the price of long-term firm service may be difficult and thus the TDA proposal would not provide adequate levels of certainty to facilitate long-term service.

1124. Mark Lively asserts that the TDA proposal fails to address other types of redispatch, including loop flow, reactive power, Inadvertent Interchange and intra-hour interchange, and as such will result in suboptimal operation of the network.

1125. OG&E questions whether the TDA proposal would apply to RTOs but if so, OG&E argues that the proposal should be rejected. OG&E contends that the Commission explained in Order No. 2000 that congestion management is a regional function and that the TDA proposal should not apply to a transmission provider located within an RTO.

1126. In supplemental comments, Transparent Dispatch Advocates contend that the transparent dispatch proposal would not involve the establishment of organized markets of any sort; rather, it simply would require the posting of redispatch costs. Transparent Dispatch Advocates state that the proposal only requires the consideration by the transmission provider of additional price data from non-network resources and minimal adjustments in transmission provider's reporting systems.

1127. Several parties disagree with Transparent Dispatch Advocates and argue that the proposal would require the establishment and operation of markets by transmission providers.[686] APPA and TDU Systems assert that under the TDA proposal transmission providers would select bids, from among a variety of affiliated and unaffiliated resources, that most effectively relieve constraints. Community Power Alliance, Georgia Commission, Southern and Entergy assert that the TDA proposal would result in the establishment of formal LMP markets in non-RTO/ISO areas, or at least start down the ''slippery slope'' to LMP markets. Community Power Alliance and Entergy contend that adoption of the TDA proposal is in conflict with the purpose of the rulemaking as stated in the NOPR and Congress' focus on protecting native load and ensuring reliability in EPAct 2005.

1128. APPA argues that the implementation of the TDA proposal would require the following: designation and posting by the transmission provider of chosen flowgates; posting by the transmission provider of the desired characteristics of generation or demand-side responses that could alleviate such constraints; posting by the transmission provider of historical redispatch costs; resolution of whether public utility transmission providers can be required to provide generation resources for redispatch; resolution of whether transmission providers would be discriminated against if they were not permitted to charge market-based rates; administration by the transmission provider of short-term (daily or hourly) market for redispatch, notwithstanding a conflict of interest between the transmission provider's market-making and market-participant roles and possibly third-party monitoring of market administration.

1129. APPA, Xcel, North Carolina Commission, and NRECA raise concerns over the costs of establishing and administering redispatch markets and systems, including the costs of hardware, software, communication systems, billing and reporting systems. North Carolina Commission submits that the costs of implementing the TDA proposal would be substantial because there are no current practices or rules on which to model structures for the TDA proposal. Other commenters similarly assert that the TDA proposal would impose significant administrative burdens and expenses on transmission providers, especially if an independent entity were required for implementation, and that most of these costs would be shifted to native load customers.[687] Xcel argues that redispatch cannot be cost-effectively managed unless done within the context of a regional Day 2 energy market.

1130. NRECA asserts that transmission providers would need an enormous amount of data, including resource status, marginal generation costs, start up costs, ramp rates, and environmental costs of operation, to redispatch resources. NRECA asserts that the allocation of redispatch costs for multiple customers taking redispatch may be difficult.

[684] *E.g.,* LPPC Supplemental, TAPS Supplemental, NRECA Supplemental, Southern Supplemental, South Carolina E&G Supplemental, and E.ON Supplemental.

[685] *E.g.,* Nevada Companies Supplemental, Community Power Alliance Supplemental, Southwest Utilities Supplemental, and Southern Supplemental.

[686] *E.g.,* APPA Supplemental, LPPC Supplemental, TDU Systems Supplemental, NRECA Supplemental, Progress Energy and MidAmerican Supplemental, Southern Supplemental, Duke Supplemental, OG&E Supplemental, Georgia Commission Supplemental, and North Carolina Commission Supplemental.

[687] *E.g.,* Community Power Alliance Supplemental, Southwest Utilities Supplemental, Florida Commission Supplemental, Ameren Supplemental, and Entergy Supplemental.

1131. Xcel, APPA, and TDU Systems assert that the TDA proposal would not address concerns about subjective redispatch decisions by transmission providers. TDU Systems argue that the proposal would allow for the functional equivalent of an RTO market, without a market administrator that satisfies the independence criteria of Order No. 2000 or Order No. 888. APPA asserts that posting of information concerning the nature of congestion at designated flowgates would be followed by differences of opinion as to how the dispatch entity is exercising its judgment in calculating the costs and in redispatching resources.

1132. Southwest Utilities and Southern assert that the proposal raises significant questions regarding commercial, operational, economic, and compliance issues that remain unanswered. For example, Southwest Utilities argues that it would appear that under the TDA proposal a transmission provider accepting a third party bid would be required to assume the commercial obligation, including credit risk associated with the bid and the posting of collateral, and would execute the contract with the third party bidder under currently unspecified terms and conditions. Southwest Utilities and Southern further argue that the proposal fails to resolve how operational and economic liability to the redispatch customer would be impacted in the event of non-performance by a third party supplier. Southwest Utilities also asserts that it is unclear whether the TDA proposal could function within the rated path/contract path model of much of the Western Interconnection.

1133. Many parties argue that implementation of the TDA proposal would raise jurisdictional issues.[688] Community Power Alliance, South Carolina E&G, Progress Energy, MidAmerican and Southern assert that the TDA proposal conflicts with state and federal laws in that it forces transmission providers to use generation (that was built, dedicated and dispatched to serve retail and wholesale customers at least cost) to serve other wholesale suppliers and customers. Community Power Alliance argues that states, not the Commission, have authority to regulate how utilities dispatch generation and procure resources. Further, Community Power Alliance asserts that requiring utilities to establish platforms for third-party generators' offers would convert the transmission function into a generation procurement function, violating the scope of the Commission's jurisdiction. Southern, LPPC and North Carolina Commission add that the TDA proposal would be in violation of section 201 of the FPA that expressly limits the Commission's jurisdiction to matters which are not subject to regulation by the States. Southern further asserts that this is made clearer by the exclusion in section 201 of ''facilities used for the generation of electric energy'' from the Commission's jurisdiction. Southern contends that mandated cost-based sales would also constitute an unlawful taking of private property under the Fifth Amendment of the Constitution.

1134. LPPC states that Transparent Dispatch Advocates seek to reason around section 201 of the FPA in arguing that redispatch ''does not involve the sale of electricity for re-sale or consumption; it involves the provision of a service to support transmission service.'' [689] LPPC counters that, in redispatch, generation is used *instead* of transmission service rather than *in support* of transmission service. North Carolina Commission, LPPC and APPA argue that the courts have previously rejected Commission attempts to extend regulation to matters specifically excluded, statutorily, from regulation on the grounds that they are the functional equivalent of a jurisdictional service.[690] LPPC also asserts that section 217 of the FPA specifies that utilities have a right to use their transmission facilities on a priority basis in order to meet their core service obligations.

1135. North Carolina Commission asserts that in Order No. 888 the Commission interpreted its authority under sections 205 and 206 of the FPA to include the effect the Rule may have over generation facilities because preventing undue discrimination is one of the matters specifically provided for in Part II. North Carolina Commission argues that *California Independent System Operator* v. *FERC,*[691] however, establishes limits on how broadly sections 205 and 206 can be interpreted. North Carolina Commission contends that sections 205 and 206 historically have been interpreted to apply to the rates for wholesale sales and purchases, rather than to the underlying generating facilities. As a result, North Carolina Commission argues that the adoption of the TDA proposal could not be justified under these provisions of the FPA.

Commission Determination

1136. The Commission agrees with the Transparent Dispatch Advocates proponents that greater transparency of reliability redispatch information can provide benefits to consumers, as well as increase efficient use of the existing transmission grid. We are therefore adopting certain reforms, as explained in the section below, that will increase the availability and transparency of redispatch costs. However, we are adopting these reforms in the context of the existing obligation to provide network and point-to-point transmission service under the *pro forma* OATT. We will not adopt the portion of TDA proposal that would require the creation of new services or any broader market reforms.

1137. The TDA proposal has generated controversy for several reasons, including the lack of clarity in the proposal, certain inconsistencies that appear in Transparent Dispatch Advocates' various submissions, and concerns that Transparent Dispatch Advocates' true intent is to restructure bilateral markets. We believe that many of the concerns regarding the TDA proposal are overstated, but we do agree that it lacks clarity and consistency in many important respects. For example, it is not clear whether the proposed service would be available to all customers, any point-to-point customer including those taking non-firm service, or solely to long-term firm point-to-point customers.[692] Additionally, while Transparent Dispatch Advocates contend that ''the one step'' required of the Commission is to implement a redispatch cost posting requirement,[693] the TDA proposal also would require the Commission to expand the current redispatch obligations under the *pro forma* OATT and adopt complex settlement mechanisms to account for third party redispatch. The different TDA proposals also vary as compared with each other. For instance, the TDA Summary states that transmission providers would not be obligated to provide their resources for real-time redispatch, but the Transparent

[688] *E.g.*, APPA Supplemental, LPPC Supplemental, Community Power Alliance Supplemental, South Carolina E&G Supplemental, Progress Energy and MidAmerican Supplemental, and Southern Supplemental.

[689] Transparent Dispatch Advocates Reply at 17.

[690] *Citing Northwest Pipeline Corp.* v. *FERC,* 905 F.2d 1403, 1410–11 (10th Cir. 1990); *Detroit Edison Co.* v. *FERC,* 334 F.3d 48, 54–55 (D.C. Cir. 2003).

[691] 372 F.3d 395 (D.C. Cir. 2004).

[692] *Compare* Transparent Dispatch Advocates Supplemental at 2 n.4 (stating that the proposed service would supplement the existing OATT requirement to provide redispatch to long-term firm point-to-point customers) *and* Transparent Dispatch Advocates Supplemental at 5 (discussing the proposal as a remedy for undue discrimination against firm point-to-point customers) *with* Transparent Dispatch Advocates Supplemental at 14–15 (demonstrating the redispatch pricing mechanism for a non-firm transaction).

[693] Transparent Dispatch Advocates Reply at 18.

Dispatch Advocates Supplemental Comments make clear that the transmission provider would be obligated to use its own (or affiliated) resources to provide this redispatch.

1138. We first address the contention of Transparent Dispatch Advocates that the real-time reliability redispatch obligation of transmission providers must be extended to ''non-network transmission customers'' to remedy undue discrimination. We disagree. In order to remedy undue discrimination, we have made changes to the *pro forma* OATT to implement a new conditional firm option for point-to-point service and we make changes to the existing planning redispatch obligation. However, Transparent Dispatch Advocates have failed to show that the unavailability of reliability redispatch for point-to-point transmission customers amounts to undue discrimination. Order No. 888 provided for reliability redispatch for network customers but not for firm point-to-point customers.[694] There is a good reason for this distinction. The *pro forma* OATT requires network customers to make their generation resources available to the transmission provider to provide reliability redispatch to maintain the reliability of service to both native load and network customers. There is no corresponding obligation on point-to-point customers to make their generation resources available to provide reliability redispatch. Therefore, the two services are not comparable in this respect, which is why reliability redispatch service was not required for point-to-point customers. However, if a reliability problem does arise, any curtailment of firm point-to-point transmission service must be on a nondiscriminatory and *pro rata* basis with the treatment of network service and native load customers.[695] The Commission has found that this treatment meets the comparability requirements enunciated in Order No. 888.[696]

1139. Next, we also decline to adopt a requirement for transmission providers to incorporate offers to redispatch from third parties into their reliability redispatch or planning redispatch. Mandatory inclusion of third party offers is not necessary to remedy undue discrimination. The *pro forma* OATT obligates transmission providers to use their resources to provide, where available consistent with reliability, redispatch service because they do so when serving their native load customers. Third party generators do not have this obligation, nor do the Transparent Dispatch Advocates propose to create such an obligation. Rather, under the TDA proposal, transmission providers would remain obligated to provide redispatch service, but third party generators would have only the option of doing so. Transparent Dispatch Advocates are therefore not proposing comparable treatment and we decline to adopt the proposal. This notwithstanding, we believe that redispatch offers by third party generators can increase system reliability and reduce costs to customers by increasing the planning redispatch options available to transmission providers. We therefore are adopting, as explained above, a requirement that transmission providers modify their OASIS to allow for the posting of third party offers to supply planning redispatch. This OASIS posting requirement does not obligate transmission providers to incorporate bids from third parties into their redispatch; rather, posting of third party offers to provide redispatch may be used by transmission customers to secure planning redispatch provided the appropriate agreements are reached between the customer, third party redispatch provider, transmission provider and reliability coordinator.

1140. We disagree with Transparent Dispatch Advocates and their supporters that their proposal for real-time redispatch and third party generation participation would allow for additional long-term rights through planning redispatch. If third party participation in the offer of redispatch is voluntary, transmission providers would not be able to depend upon third party resources in evaluating the availability of resources during the term of the planning redispatch service. Transmission providers therefore would only be able to evaluate the availability of their own resource as they do today. Thus, Transparent Dispatch Advocates have failed to show how its proposal would supplement provision of long-term rights.

1141. Because we find that the TDA proposal for real-time redispatch and third party participation is unnecessary to remedy undue discrimination or comparability issues, we need not address the issue of the scope of the Commission's jurisdiction as it relates to the TDA proposal.

(2) Redispatch Rate Transparency

Comments

1142. PJM argues that if the Commission does not provide for independently administered real-time spot markets, it should require transmission providers to ''make public their dispatch sequence and the real-time marginal costs of electricity.'' [697] In reply comments, Transparent Dispatch Advocates request that the Commission require publication of ''dynamic real-time value of what [each transmission provider] would charge to provide redispatch service at specified congestion locations within the transmission provider's system and at specified flowgates at the border of the transmission provider's system.'' [698] In supplemental comments, Transparent Dispatch Advocates state that ''[t]he essence of the TDA proposal is to require transmission providers to make real-time information about the cost of redispatch available on their OASIS in order to allow more efficient use of the transmission system.'' [699] Transparent Dispatch Advocates, EPSA and AWEA state that the posting requirement should be limited to pre-determined flowgates and that the estimated price for redispatch should be posted frequently and sufficiently in advance of the hour in which the price would be effective in order to allow the transmission customer to change its schedule and avoid redispatch charges.

1143. EPSA, AWEA and Transparent Dispatch Advocates state that since this information is available today and considered by transmission providers in serving their own native load, there are no impediments to implementing their proposed posting requirement. Transparent Dispatch Advocates argue that concerns about release of confidential data can be addressed by

[694] *See pro forma* OATT section 33.2; *see also Midwest Independent Transmission System Operator, Inc.,* 84 FERC ¶ 61,231 at 62,168 (1998) (''redispatch will be utilized to avoid the curtailment of firm point-to-point services, a requirement that is not imposed under the pro forma tariff.''); *Mid-Continent Area Power Pool,* 87 FERC ¶ 61,190 at 61,726–27 (1999) (finding no obligation to offer reliability redispatch to point-to-point customers and no obligation for point-to-point customers to participate in reliability redispatch).

[695] *See, e.g., North American Electric Reliability Council,* 88 FERC ¶ 61,046 at 61,123–24 (1999) (explaining that pro rata curtailment is consistent with comparability even if network/native load reduction is accomplished by redispatch and point-to-point customer reduction is not); *Northern States Power Co.,* 83 FERC ¶ 61,338 at 62,369 (1998) (the existence of redispatch options is not a criterion under the *pro forma* OATT for disproportionate curtailments), *reh'g, clarification and stay denied,* 84 FERC ¶ 61,128 (1998), *remanded on other grounds sub nom. Northern States Power Co.* v. *FERC,* 176 F.3d 1090 (8th Cir. 1999) (*Northern States Power*).

[696] *Northern States Power,* 83 FERC ¶ 61,338 at 62,369.

[697] PJM at 6.

[698] Transparent Dispatch Advocates Reply at 5.

[699] Transparent Dispatch Advocates Supplemental at 7.

using system costs instead of unit-specific cost data to calculate the posted redispatch price. EPSA and AWEA state that there are not confidentiality issues with the Transparent Dispatch Advocates' posting proposal because redispatch costs are not the costs that the transmission provider is incurring to sell energy into the market: they contend that redispatch costs are the net cost incurred by the transmission provider, *e.g.*, the difference between the costs of ramping up and ramping down resources. EPSA and AWEA also state that there would be no competitive concerns over the posting of this information from third party suppliers because the *suppliers names need not be* used.

1144. Some commenters do not believe that making certain information publicly available will result in confidential information disclosure.[700] PPL states that while confidentiality concerns must be considered, the nature and type of information that is publicly provided may be structured so as to alleviate or minimize such concerns. PPL argues that rather than posting specific generator cost information the all-in price for redispatch may be posted instead. BP Energy argues that posting redispatch prices at specified locations reveals the economic value of adding transmission/generation at those locations, but does not reveal the production cost associated with specific generation resources. BP Energy states that hourly redispatch costs should be posted for all ''significant congested interfaces'' within a transmission provider's control area and for all interfaces at control area boundaries. PGP asserts that transmission providers with OATTs should post any available information on hourly redispatch costs.[701] PGP and PPL argue, however, that there should be an appropriate lag in the disclosure of actual redispatch costs in order to address confidentiality concerns. Williams states that increased transparency and proper monitoring are immediate, real solutions to ''issues'' with the posting of the cost of redispatch. Williams asserts that those customers requesting redispatch should be provided the cost differential between the original dispatch and the redispatch and that post audit redispatch data and system models can be made available (after the expiration of a non-disclosure period) to provide market certainty of least cost redispatch and appropriate bid selection.

1145. PGP states that the redispatch option should be available irrespective of time frame, but must recognize the limited ability of the transmission provider to identify likely redispatch costs further out in time. Thus, PGP argues, posting redispatch costs in areas without organized markets should focus initially on real-time reliability redispatch, later expanding to longer time frames. PGP asserts that redispatch should be undertaken only when firm bids are available and the transmission customer has accepted responsibility for redispatch costs, which should be based on just and reasonable prices and must be known with a degree of certainty. PGP adds that the transmission provider should establish protocols that support firm bids, which would be published and, if accepted, result in binding obligations on the part of the bidders. PGP argues that it is reasonable for transmission providers to post real-time bids on constrained paths that are otherwise subject to curtailments to ensure compliance with reliability criteria. PGP contends that postings should take place on the transmission providers' OASIS and that all information should be retained by the transmission provider. PGP submits that redispatch bids should be explicitly added to the Commission's Electric Quarterly Reports filing requirements if not already required.

1146. Constellation argues that the Commission should require each transmission provider to post two values to the market on its OASIS site, in order to enhance transparency: historical costs of redispatch at certain specified flowgates (perhaps those most congested historically) and real-time redispatch costs at the same flowgates. Constellation submits that each transmission provider engages in redispatch and thus can readily ascertain the cost of redispatch at various locations. Constellation argues that posting such costs will enable transmission customers to more accurately assess the potential costs of redispatch prior to deciding to incur redispatch costs. Constellation adds that the customer receiving redispatch should be obligated to pay the actual costs of redispatch, regardless of the costs reflected in the postings, which, Constellation contends, should reflect the transmission provider's most accurate and up-to-date information.

1147. Williams believes that Transparent Dispatch Advocates' redispatch proposal offers a partial remedy to transmission congestion caused by insufficient infrastructure and undue discrimination. Williams proposes that affiliate and third-party generators submit either a pre-established rate structure or formulary pricing methodology prior to the provision of redispatch service. Williams states the primary implementation impediment to greater transparency of redispatch cost information is the accuracy and availability of redispatch costs.

1148. BP Energy submits that posting the costs of redispatch is not the same as posting operational cost curves of specific generating units. BP Energy adds that, given the availability of redispatch costs, there is no reason to post the differential in unit-specific costs as a supplement to marginal prices posted at significant locations throughout the control area. PGP states that there is no need to establish markets to provide real-time redispatch. Rather, PGP asserts that limited protocols can be established for specific locations or types of congestion that may be directly relieved via redispatch. PGP believes that the Commission should avoid establishing detailed rules governing redispatch protocols, but rather should permit regional practices to be developed that result in ''just and reasonable'' charges for redispatch service.

1149. In its reply comments, Southern states that requiring vertically integrated utilities to post their real-time marginal costs of electricity would be discriminatory and violate the Trade Secrets Act.[702] Southern states that RTOs do not make public the marginal costs of the utilities participating in their markets, thus requiring other transmission providers to do so would be discriminatory. Southern states that marginal costs information is commercial or financial information protected by federal statute that if released would put it at a competitive disadvantage and harm its customers by allowing competing generators to price their power just below the published marginal costs.

1150. Several parties assert that the TDA proposal would require the posting of vertically integrated utilities' generation costs and thus would provide competitors and buyers with commercially-sensitive information.[703]

[700] *E.g.*, EPSA and AWEA Supplemental, BP Energy Supplemental, and California Commission Supplemental.

[701] PGP asserts that the transmission provider should be required to post redispatch information by event and by entity to address concerns about anticompetitive behavior.

[702] 18 U.S.C. 1905.

[703] *E.g.*, Entergy Supplemental, Community Power Alliance Supplemental, Progress Energy and MidAmerican Supplemental, Southern Supplemental, Southwest Utilities Supplemental, Nevada Companies Supplemental, OG&E Supplemental, Florida Commission Supplemental, PPL Supplemental, Ameren Supplemental, North Carolina Commission Supplemental, and SEARUC Supplemental.

Many of these parties assert that posting a utility's incremental costs publicizes the price at which the utility elects to operate resources rather than purchase from a third-party.[704] EEI and South Carolina E&G assert that making this information public may adversely affect competition and markets. Duke argues that having the transmission provider post daily and hourly generator costs assigns it responsibilities that are beyond the typical transmission function. Duke urges the Commission to consider voluntary alternatives to resource-specific cost information that would divulge competitively-sensitive data. SEARUC argues that any incremental transparency improvements not be implemented in such a manner as to make competitively sensitive information available to the public on an inconsistent basis. Nevada Companies assert that the requirement to make such information publicly available to the transmission provider would have to be imposed upon all generators, including independent power producers, so that such information would lose the value it derives from not being publicly known.

1151. Entergy argues that the Commission is statutorily prohibited from requiring the disclosure of information that undermines fair competition under the electric market transparency provisions in sections 220(b)(1) and (2) of the FPA.[705] South Carolina E&G submits that the TDA proposal is inconsistent with this provision of the FPA. Southern further contends that mandating that transmission providers post and offer their generation on an at-cost basis, while allowing third party generators to submit bid prices would also be discriminatory. TAPS asserts that the proposed real-time disclosure of bid and cost information runs contrary to the Commission's policy of a 6-month delay for release of bid information.

1152. NRECA asserts that the Transparent Dispatch Advocates fail to explain why transmission providers coordinating with third parties or neighboring transmission providers will not run afoul of anti-trust and collusion concerns that they are colluding in price setting; and how to verify providers are selecting the lowest bid unless they are required to post all third party generator bids as well as their own or their affiliates' cost of providing the service.

1153. Ameren asserts that the existing OATT contains requirements for information to be posted by transmission providers, and does not believe that additional posting ought to be required. Ameren provides several recommendations were the Commission to adopt some or the entire TDA proposal. First, Ameren asserts that there are many different ways to estimate this cost and, in order to avoid the creation of competing methods for estimating redispatch costs, the Commission must consider and provide guidance on several questions.[706] Second, so that transmission providers are not disadvantaged by this new obligation, Ameren urges the Commission to develop detailed requirements, including uniform timelines for posting, guidelines for estimating cost, and inclusion of all dispatchable generation in the relevant footprint. Ameren further argues that posting only the difference in costs would not address the potential for anticompetitive impacts. Finally, Ameren contends that the Commission may wish to consider implementing the changes only on an interim basis, then to observe whether there is any market benefit or any competitive harm as a result of the new requirements.

1154. Duke believes that the posting of hourly redispatch costs would create near-constant off-OASIS communications between the transmission provider and merchant function employees, which, Duke asserts, would raise Standards of Conduct concerns.

1155. NRECA argues that allocated costs may vary significantly regardless of methodology, which devalues the posting of costs. North Carolina Commission argues that publishing indicative redispatch costs in real time would require a determination as to how such costs are determined and whether each component of such costs are appropriately charged to customers.

Commission Determination

1156. After careful consideration of the comments of the parties, we adopt a posting obligation that balances several competing considerations. First, we agree with Transparent Dispatch Advocates and supporting parties that the increased availability of information regarding redispatch costs can benefit consumers and increase the efficient use of the grid. Second, we are cognizant, however, that increased posting and reporting can impose cost burdens on transmission providers or otherwise harm market participants. For example, the reporting obligations can reveal confidential information that could harm market participants or increase the cost of serving native load customers. We also recognize that the posting or reporting obligation should be reasonably tailored to provide useful information to consumers without, at the same time, imposing unnecessary burdens on transmission providers, either in the frequency of the posting obligation or the scope of information provided.

1157. In balancing these considerations, we will, as explained further below, adopt a requirement that transmission providers post certain redispatch cost information associated with the existing redispatch services that must be provided under the *pro forma* OATT. We find that providing customers with additional transparency and greater information regarding the cost of congestion, will facilitate their consideration of planning redispatch options which in turn will provide for more efficient use of the grid. We stress, however, that this posting requirement relates only to the existing redispatch services required under the *pro forma* OATT; it does not expand those service obligations. The primary purpose of the posting requirement is to ensure that all customers have access to this information, not only the customer receiving the redispatch service.

1158. Moreover, the costs of the dynamic posting requirement proposed by Transparent Dispatch Advocates outweigh the benefits of such a requirement. Transparent Dispatch Advocates propose that the posting requirement be limited to specified congestion locations within and at the border of each transmission provider's system. Transparent Dispatch Advocates have not proposed *ex ante* criteria to determine which flowgates would require posting. In fact, some members of the Transparent Dispatch Advocates coalition would have the posting requirement apply to all transmission facilities, whether or not they were

[704] *E.g.*, Entergy Supplemental, Community Power Alliance Supplemental, Southern Supplemental, Duke Supplemental and South Carolina E&G Supplemental.

[705] Entergy refers to the following language:

(1) The Commission shall exempt from disclosure information the Commission determines would, if disclosed, be detrimental to the operation of an effective market * * *; and (2) [i]n determining the information to be made available under this section and the time to make the information available, the Commission shall seek to ensure that consumers and competitive markets are protected from adverse effects of potential collusion and other anticompetitive behaviors that can be facilitated by untimely public disclosure of transaction-specific information.

[706] Ameren raises several questions to this effect: Does the transmission provider estimate cost effect across all market LMPs or just the congested points? Should the analysis take into account credits and adjustments to which some participants may be entitled? For what period should the transmission provider provide this estimate? For those transmission providers within a centralized market, how should they treat market costs such as losses or RSG (Revenue Sufficiency Guarantee in MISO) in calculating the redispatch cost?

congested and whether or not customers were seeking service over those facilities. Such an open-ended obligation to post costs for all facilities on a transmission provider's system would unnecessarily impose uncertainties and unbounded administrative costs on transmission providers. Additionally, depending on the frequency of publication and the method used to calculate the estimates, the publication of these estimates could reveal sensitive confidential information about transmission providers' generation costs that would likely harm existing markets and native loads. There is no simple formula for estimating the costs that would fully mask this confidential information and at the same time provide practical information about the costs of redispatch.

1159. While we agree that transparency can benefit customers, Transparent Dispatch Advocates have not demonstrated the benefits of its posting requirement to customers seeking reliability or planning redispatch. Transparent Dispatch Advocates would have transmission providers frequently post an estimate of the cost of the next increment of redispatch. Customers seeking redispatch would not know the actual costs customers paid for redispatch. Nor would they be able to apply the estimate of cost to their transactions since most transactions would involve more than a single increment of redispatch service and there might be multiple redispatch transactions over a single transmission facility. Thus the estimate would only be of value to the marginal customer taking a small amount of redispatch service. Transmission providers would expend time and money determining the correct formula to use to estimate costs, collecting data for the inputs to the calculation and frequently posting estimates throughout each day that could have little or no correlation to the actual costs a transmission customer would pay for the redispatch service.

1160. Third party participation in redispatch is one of the benefits Transparent Dispatch Advocates point to in support of its proposed posting requirement. Transparent Dispatch Advocates would have transmission providers act as the conduit for service from third party redispatch providers, collecting from customers and paying third party providers. As described above, we are allowing third party participation in planning redispatch without requiring transmission providers to act as bill collectors for third party redispatch providers or requiring coordination agreements among each transmission provider and all potential third party providers. This OASIS modification, described above, will provide third parties seeking to provide redispatch with the opportunity to frequently update the price of their offers as suggested by Transparent Dispatch Advocates.

1161. We do believe, however, that information regarding actual redispatch costs should be made more widely available. Currently, when a transmission provider provides reliability or planning redispatch, the associated cost information is provided only to the customer receiving the service through its invoices. This ignores the fact that information regarding the cost of redispatch can benefit all customers and increase the efficient use of the grid. We therefore find that it is no longer just, reasonable and not unduly discriminatory to limit the provision of this information only to the individual customers receiving the service.

1162. Accordingly, to provide greater availability of redispatch information, the Commission adopts certain additional posting requirements for transmission providers. Specifically, we direct each transmission provider to post on OASIS its monthly average cost of redispatch for each internal congested transmission facility or interface over which it provides redispatch service using planning redispatch or reliability redispatch under the *pro forma* OATT.[707] Additionally, to demonstrate the range of redispatch costs each month, the Commission directs transmission providers to post a high and low redispatch cost for the month for each of these same transmission constraints. The transmission provider shall calculate the monthly average cost in $/MWh for each congested transmission facility by dividing monthly total redispatch costs (at the facility) by the total MWhs that would otherwise be curtailed (at the facility) in the month absent the redispatch.[708] Transmission providers shall post internal constraint or interface data for the month if any planning redispatch or reliability redispatch is provided during the month, regardless of whether the transmission customer is required to reimburse the transmission provider for those exact costs. Thus, if the transmission customer pays for redispatch pursuant to a negotiated fixed rate, the transmission provider is required to post and calculate the monthly average redispatch costs and the high and low costs in the month even though the transmission provider will bill the customer the fixed rate. The same posting requirement applies if the customer is paying a monthly ''higher of'' rate.[709] The transmission provider shall post this data on OASIS as soon as practical after the end of each month, but no later than when it sends invoices to transmission customers for redispatch-related services. We direct transmission providers to work in conjunction with NAESB to develop this new OASIS functionality and any necessary business practice standards.

1163. There are several benefits to this posting requirement. First and foremost, it will give customers fairly current information regarding the cost of redispatch of the congested transmission facilities over which redispatch is provided, presumably some of the most congested facilities on transmission providers' systems. Second, it will limit posting only to those congested transmission facilities over which redispatch has actually been sought and granted and for which redispatch charges have been billed to customers. This addresses commenters' concerns about the posting of information that is valuable only hypothetically. Third, because we require the posting of average redispatch costs, not real-time redispatch costs or real-time system lambda or system incremental costs, it will not be harmful to native load or reveal otherwise competitively sensitive information.

1164. Finally, in addition to the above posting requirement, we note that, as part of the transmission planning provisions adopted in this Final Rule, we are providing customers with a right to request a study of a defined number of congested transmission facilities on an annual basis. This will provide customers an additional opportunity to evaluate redispatch costs, including costs for those congested transmission facilities for which redispatch service has not been granted.

[707] The relevant reliability redispatch costs for posting purposes are those costs the transmission provider invoices network customers based on a load ratio share pursuant to section 33.3 of the *pro forma* OATT. The transmission provider need not perform new calculations of out-of-merit dispatch costs; rather the reliability redispatch invoices should form the basis of information from which the transmission provider determines monthly average reliability redispatch costs.

[708] For example, if reliability redispatch is used by the transmission provider to prevent curtailment of 10 MW of transmission provider or network customer load for 5 hours during the month across flowgate A, the transmission provider would use 50 MWh as the divisor to determine the monthly average cost of redispatch for flowgate A.

[709] This is not a new calculation for the transmission provider because the transmission provider must determine the redispatch costs to know whether to charge higher of the embedded rate or the redispatch costs.

c. Other Requested Service Modifications

NOPR Proposal

1165. In the NOPR, the Commission summarized requests for various new services made in response to the NOI. The Commission's proposed solutions evaluated solely the planning redispatch and conditional firm options.

Comments

1166. Commenters make several suggestions with regard to additional services or modifications to existing services. Most popular among the suggested new services is long-term, seasonally-shaped firm point-to-point service. Several commenters support this service for circumstances in which the transmission provider determines that the requested service is available during some, but not all, months of each year of a single or multiyear request.[710] Commenters suggest that the long-term, seasonally-shaped service would provide an option for the transmission customer in lieu of costly upgrades without the operational difficulties of conditional firm service. In its reply comments, Powerex states that this product would have less of an adverse impact on existing firm rights holders. Northwest IOUs propose that the transmission customer pay the long-term point-to-point transmission service rate prorated for the portion of the year for which it receives the service. Public Power Council states that the transmission customer would be free to purchase non-firm or secondary service for the periods when firm service through the seasonally-shaped service was unavailable. Northwest IOUs argue that ''cream-skimming'' is avoided by processing only requests for long-term service and having the transmission provider determine the availability of the service.

1167. Powerex supports the implementation of a long-term non-firm point-to-point service. Tacoma believes priority non-firm or partial firm transmission services are alternatives to planning redispatch. Entegra proposes an additional service that would allow the customer, in the event of a constraint, to agree to either pay for redispatch or have its service curtailed. In contrast to these request for new services, TranServ states that simplified services and a reduction in the number of services would increase the transparency and fluidity of electricity trading.

1168. MidAmerican urges the Commission to allow for dynamic scheduling service between control areas on a case-by-case basis, by including and pricing the service in the service agreement. MidAmerican states that this service would be similar to point-to-point service, but would allow the transmission customer to dynamically monitor its loads in neighboring control areas and dispatch its own remote resource to meet the load fluctuations in load pockets served by other transmission providers. MidAmerican further states that this new service is necessary in the Western Interconnection because neither point-to-point nor network service meets the needs of loads that are not confined to a single geographic area served by a single transmission provider.

1169. Barrick states that the Commission should require transmission providers to confirm the availability of secondary service for network customers on a monthly or quarterly basis so that network customers can plan ahead for the use of secondary service. In its reply comments, Seattle supports the development of short-term redispatch service, currently under discussion for provision in the Pacific Northwest. TranServ requests that the Commission clarify whether sequential reservation of 12 consecutive months of monthly firm service is long-term service. TranServ requests that the Commission direct the development of business practices by NAESB to allow customers to designate minimum term and capacity for partial interim service, similar to the practice employed by Bonneville.

Commission Determination

1170. The Commission rejects the requests to order new services or modifications to existing services suggested by commenters. We believe that the modifications to point-to-point transmission service adopted herein best address the issues raised by these requests. The planning redispatch and conditional firm options provide a means of remedying undue discrimination, and increasing transparency and access to the grid by point-to-point customers. We note that there is considerable overlap between these options and the new services suggested by commenters. However, we find that the introduction of the requested new services may create greater complexities than those present in the planning redispatch and conditional firm options. For example, several commenters propose a long-term seasonally shaped firm point-to-point service as a superior option to the conditional firm service. However, requestors have not adequately addressed concerns about the service, including the potential for hoarding transmission and the reliability issues related to evaluating the availability of the service or granting the service over many years. A seasonally shaped service could exacerbate the lumpiness of transmission investment by preventing customers willing to pay for transmission upgrades from obtaining all twelve months of service. While we will not reduce the number of services required as suggested by TranServ, the Commission must limit the number of new services adopted and modifications to existing services to a reasonable number that transmission providers can reliably implement. For these reasons, we decline to adopt any additional proposals or modifications to firm point-to-point service beyond those directed above in this Final Rule. Of course, transmission providers remain free to voluntarily propose additional services that are consistent with or superior to the *pro forma* OATT, as modified by this Final Rule.

1171. The Commission rejects the request to adopt long-term non-firm service because there is no indication that customers would find such a service useful and it would be inconsistent with the policy in the *pro forma* OATT that values firm service over non-firm service.

1172. MidAmerican requests that the Commission allow a point-to-point service that would let a transmission customer monitor its load and dispatch its remote resources to meet load fluctuations. In Order No. 888–A, the Commission clarified that this type of dynamic scheduling was not mandated Order No. 888, but that nothing in Order No. 888 precludes a transmission provider from offering it as a separate service.[711] Thus, MidAmerican may propose such a service pursuant to an FPA section 205 filing with the Commission, and we will consider it, as we would any new service proposal, on a fact-specific, case-by-case basis.

1173. Barrick requests that the Commission require the confirmation of the availability of secondary service for network customers on a monthly or quarterly basis so that network customers can plan ahead for the use of secondary service. As we stated in the NOPR, secondary network service refers to transmission service for network customers from resources other than designated network resources and is provided on an ''as available'' basis. Since the secondary service is provided

[710] *E.g.*, MidAmerican, Public Power Council, Northwest IOUs, Xcel, Powerex Reply, PPL, and Seattle Reply.

[711] Order No. 888–A at 30,235–36.

on an as available basis, Barrick's request seeks to allow secondary network service to pre-empt firm uses of the system, such as short-term firm point-to-point service, for what is a less than firm service. Barrick has not clearly articulated why this proposal is necessary to prevent the exercise of undue discrimination or why service from designated network resources would not meet its need for firmer secondary service. Thus, we reject Barrick's request.

1174. With regard to Seattle's support for redispatch being developed in the Pacific Northwest, we believe that this type of redispatch shares many of the attributes of the Transparent Dispatch Advocates proposal rejected above. Although we acknowledge that market mechanisms that provide hour-ahead or real-time redispatch for all transmission customers can provide benefits to customers and efficient use of the transmission grid, for the reasons stated in the prior section, we will not require in this Final Rule that all transmission providers implement such market mechanisms. We note that nothing prevents the Commission from reviewing proposals for such market mechanisms on a case-by-case basis. We note that the conditional firm and planning redispatch options adopted in this Final Rule will provide some of the flexibility Entegra seeks. Customers taking service under these options will be able to choose, when executing the service agreement, between curtailment and redispatch.

1175. Also, the Commission clarifies for TransServ that twelve months of consecutive monthly firm service, where the term of any particular monthly service agreement is for less than a year, is not long-term service.[712] The Commission rejects TranServ's request that NAESB develop particular business practices regarding partial interim service as TranServ has not shown a need for such a requirement.

1176. The Commission continues to encourage transmission providers to propose other services that are consistent with or superior to the *pro forma* OATT that meet customers' needs and make more efficient use of the transmission system. We will not mandate that transmission providers provide any service other than the services set forth in the *pro forma* OATT since they may not be applicable in all circumstances. However, if transmission providers seek to provide any modifications to the required *pro forma* OATT services or new services, they may submit an FPA section 205 filing to propose such modifications and the Commission will evaluate such proposals on a case-by-case basis.

2. Hourly Firm Service

NOPR Proposal

1177. In the NOPR, the Commission proposed to add point-to-point hourly firm service to the *pro forma* OATT. The Commission stated its belief that adding this service would eliminate a barrier to the development of markets and thereby decrease opportunities for undue discrimination. The Commission further stated that the concerns expressed in Order No. 888 regarding the unduly discriminatory effects of hourly firm service have proven unfounded. Consistent with our precedent, the Commission proposed to use the "IES Method" to price hourly firm service and apply different pricing based on whether the service is taken during peak or off-peak hours.[713] The Commission explained that this pricing method would ensure that hourly firm customers pay a fair share of the costs of the transmission system.

1178. The Commission proposed allowing transmission customers to batch requests and schedules for hourly firm service that will be provided within the same calendar day. Schedules for firm hourly service, like all other firm schedules, would be due by 10 a.m. the day before the service is to commence. The Commission also proposed that, consistent with other durations of service, the confirmation period for hourly firm service specified in section 13.2 of the *pro forma* OATT would allow longer term requests for service to preempt shorter hourly firm requests for service until one hour before the commencement of hourly firm service.

Comments

1179. Commenters are split on whether to require hourly firm service. Varied interests express some support of the requirement, while mostly IOUs, cooperatives, and public power providers oppose the requirement. Supporters, which include several entities that currently offer hourly firm service, foresee increased use of transmission facilities and market efficiencies. Chief among the arguments cited by those objecting to the required service is the potential adverse effect on those serving native load or taking longer term service due to increased frequency of curtailments. Other objections to the required service include reliability concerns and the unjustified curtailment priority that would be afforded to short-term customers that have not financially committed to long-term grid service. To the extent hourly firm service is required, commenters generally support use of the *IES* Method for pricing, although some commenters ask the Commission to allow pricing to vary according to regional practice. As for batching and scheduling, many parties request that the Commission clarify specific details of each of these proposals to prevent future disputes.

Mandatory Hourly Firm

1180. Various commenters state their general support of, or non-opposition to, the proposal to require hourly firm service.[714] Among those who support it, several state that they already supply the service themselves.[715] Such commenters argue that hourly firm service would decrease opportunities for undue discrimination, enhance the customer's ability to participate in the real-time energy markets, encourage trade and marketing liquidity, increase firm uses of the grid, allow greater customer choice, increase efficiencies in wholesale markets, and help maximize use of existing transmission facilities.[716] WAPA states that its experience indicates that the current provisions for preempting shorter-term transmission service with longer-term service, as codified in OATT section 13.2, adequately serve to discourage speculative hoarding of hourly capacity.

1181. Numerous commenters objecting to the proposed service cite the effect of curtailment on customers taking network or longer term service, especially in the service of native load.[717] Specifically, they argue that the inclusion of an additional short-term firm service would increase the

[712] *See pro forma* OATT section 1.18 (defining long-term firm point-to-point transmission service as service with a term of one year or more).

[713] *See IES Utilities, Inc.,* 81 FERC ¶ 61,187 at 61,833–34 (1997), *reh'g denied,* 82 FERC ¶ 61,089, *aff'd on other grounds sub nom. Wisconsin Public Power Inc.* v. *FERC,* No. 98–61,089, 1999 U.S. App. LEXIS 3998 (Feb. 23, 1999) (unpublished opinion) (adopting peak and off-peak pricing to hourly non-firm transmission service); *see also New York State Electric & Gas Corp.,* 92 FERC ¶ 61,169 at 61,593–94 (2000) (approving application of the *IES* Method for time-differentiated hourly non-firm rate design), *order on reh'g,* 100 FERC ¶ 61,021 (2002).

[714] *E.g.,* Ameren, Arkansas Commission, Bonneville, BP Energy, Constellation, FirstEnergy, MidAmerican, MISO/PJM States, Morgan Stanley, Nevada Companies, Newmont Mining, NorthWestern, Pinnacle, PPL, CREPC, and Suez Energy NA.

[715] *E.g.,* Bonneville, Pinnacle (noting Arizona Public Service Company's adoption of the service), PNM–TNMP, and WAPA (in its Desert-Southwest region).

[716] *E.g.,* Arkansas Commission, BP Energy, FirstEnergy, Morgan Stanley, Pinnacle, PNM-TNMP, and PPL.

[717] *e.g.,* APPA, Duke, EEI, MISO, and Southern.

likelihood that longer-term service would be curtailed and degrade the reliability of service to native load, since all firm service (point-to-point and network), regardless of duration, would be curtailed *pro rata*. Objecting commenters argue that such a result is unfair to customers that have made a long-term commitment to taking service, including expanding the system;[718] inconsistent with FPA section 217(b)(4), which requires the Commission to promote the availability of transmission for native load service;[719] and inconsistent with the Commission's commitment in the NOPR to maintain existing native load protections.[720]

1182. Although transmission providers plan for their native load needs when calculating ATC, Imperial argues that they cannot always accurately predict these needs. Imperial states that transmission providers have been able to rely on the release of unscheduled capacity when balancing their schedules to meet fluctuating needs (such as during heat waves). In view of the decline in transmission infrastructure relative to load throughout the country, NRECA objects to the reduction in ATC that would result from dedicating transmission capacity to hourly firm service. NRECA argues that designated network resources may no longer be regarded as such because firm transmission to support them is not available on constrained transmission systems (*i.e.*, most transmission systems). If hourly firm service is to be required, Imperial proposes also requiring transmission providers to make available all but 20 percent of non-reserved transmission as firm so that non-firm service will be available for the use of network customers and native load providers.

1183. Southern argues that the provision of hourly firm service would require the transmission provider to predict the exact hour on which expected peak conditions will occur in order to be able to post the amount of hourly firm service that will be available for each hour of a given day. If system conditions then change, Southern continues, reliability could be placed in jeopardy, which would result in long-term service being curtailed. Southern also argues that the provision of this hourly firm service would complicate real-time operations and negatively impact reliability since, if curtailments on a specific path prove necessary, it is more difficult to curtail a large number of transactions on a very short-term notice.

1184. Many argue that the justifications provided in Order No. 888 for not requiring this service remain valid, such as the argument that the service will invite cream skimming.[721] MISO sees a likelihood that an ''hourly priority war'' would ensue on constrained interfaces between firm and non-firm requests and that resolving these conflicts would be time consuming and stretch its resources. MISO argues that an hourly firm product would degrade the value of non-firm service and that the introduction of this new, logistically challenging service, further compounds the task of rooting out undue discrimination. MISO argues that the proposed mandatory introduction of this service will have serious adverse implications for many functioning RTOs. MISO contends that hourly firm service should remain strictly optional for RTOs arguing that weighing the pros and cons of this new service can best be addressed within each RTO's stakeholder process.

1185. TVA argues that hourly firm reservations would likely end up being bumped by requests for longer service (such as daily firm), consuming valuable transmission provider staff time and resources on administrative tasks with no real benefit and potentially significant costs. Similarly, Southern argues that hourly firm service would likely result in the transmission provider receiving less revenues (because fewer customers would take daily firm service) while incurring higher costs (due to implementation complexities), the net effect of which would raise OATT charges.

1186. Among commenters offering qualified support for mandatory hourly firm service,[722] ELCON and FirstEnergy ask the Commission to monitor the use of this service and to reconsider its continued need if it impairs the quality or availability of long-term firm services. Powerex argues that hourly firm point-to-point service could increase opportunities for undue discrimination unless the conditions under which the non-firm transmission service can be interrupted are clarified. South Carolina E&G argues that the Commission should give the service a lower curtailment priority than any longer term firm service (citing as support the lower reservation priority for short term firm service in section 13.2(iii)) and adopt the proposal to require that hourly firm service be scheduled the day before service is to commence.

1187. Duke explains that the current 10 a.m. deadline for firm schedules need not be enforced in the absence of hourly firm service and often is not enforced (with transmission providers acting on a comparable basis in waiving the deadline). Thus Duke identifies as a drawback to the addition of hourly firm service the likelihood that transmission providers will enforce the 10 a.m. deadline and thereby reduce existing flexibility.

1188. Some commenters objecting to the new service requirement argue that, if the Commission retains this service, certain modifications should be made.[723] These modifications include: giving the service a lower curtailment priority, pricing it at a premium above the *IES* methodology, requiring that the firm hourly postings be based upon the daily firm ATC (with the additional capacity that might be available in ''shoulder'' hours of the day being made available only as hourly non-firm), and giving secondary network service a higher priority over hourly firm. Duke argues on reply that, if the Commission determines that hourly firm service should be required, a technical conference should be held to develop appropriate, workable tariff language in light of the implementation issues raised by commenters.

Voluntary Hourly Firm Service

1189. Various commenters ask that hourly firm service not be required and, instead, continue to be allowed on a voluntary basis by willing transmission providers.[724] These commenters generally argue that the service's effect on reliability, curtailment priority, longer term service, transmission expansion, and the ability to serve native load counsels against mandating the service. NRECA argues that hourly firm service would unduly interfere with the ability of network customers (and the transmission provider on behalf of its native load customers) to use secondary network service, which is offered only on an ''as available'' basis and therefore would have a lower reservation and curtailment priority than hourly firm service.

1190. NRECA notes that the Western Interconnection, where hourly firm service has proven to be a useful product, differs from the Eastern

[718] *e.g.*, MISO and Southern.

[719] *e.g.*, APPA, NRECA, and Southern.

[720] *e.g.*, Southern.

[721] *e.g.*, LDWP, MISO, Southern, TAPS, TDU Systems.

[722] *E.g.*, ELCON, FirstEnergy, Powerex, and South Carolina E&G.

[723] *e.g.*, APPA, NRECA, Southern, and TAPS.

[724] *E.g.*, APPA, Duke, East Texas Cooperatives, EEI, Imperial, LDWP, LPPC, Northwest IOUs, NRECA, PJM, Southern, and TDU Systems.

Interconnection in a number of respects, in particular, by virtue of extensive reliance on point-to-point service by LSEs to serve native load. For this reason, NRECA continues, public utility transmission providers should only be allowed to voluntarily offer hourly firm transmission service if the service is available equally to all transmission customers and the new service does not undermine the quality of, and flexibility of, the transmission provider's existing network service (including secondary network service) and point-to-point transmission service. NRECA also requests that the Commission clarify that the only circumstance in which hourly firm service could be offered would be if daily service were not being fully used.

1191. Northwest IOUs suggest that the Commission develop standardized point-to-point hourly firm service provisions for the voluntary provision of this service by those transmission providers that determine such service would be appropriate to offer on their systems. TDU Systems argue that the Commission should condition approval of an hourly service on requirements that a lower curtailment priority is established for hourly firm service than other firm services, including secondary network service; and, it may only be sold in the hour preceding the start of service to ensure that hourly service would not impede the provision of service to other firm services, including secondary network service. In light of comments, Powerex abandoned its initial conditional support for the proposal to support voluntary provision of the service.

Alternative Proposals

1192. PJM recommends adding a service similar to PJM's non-firm willing to pay congestion (NF–WPC) service which may serve the same purpose as, and be an alternative to, hourly firm service. NF–WPC service would be evaluated for ATC and curtailed by transmission customers if the effective price of congestion were too high. Thus, NF–WPC service will result in a reduction in all TLR curtailments. To add this service to the OATT, PJM explains, all transmission providers with control over dispatch would have to provide a transparent means for redispatch to clear congestion and maintain reliability on either side of a border.

1193. Xcel argues that it is possible that hourly firm service would not be needed if the existing OATT were clarified as it relates to priority of non-firm service. Xcel proposes that the Commission could clarify that non-firm service is not interruptible during the hour due to other non-reliability driven requests, but rather at the start of the next hour, provided sufficient scheduling notice is given. Xcel continues that this clarification would also stipulate that non-firm service (and all other types of service) may be curtailed without notice at any time for reliability reasons.

Pricing

1194. Many commenters support the Commission's proposal to use the *IES* Method to price hourly firm service.[725] Several commenters suggest that the Commission allow transmission providers to define their own peak and off-peak hours under the *IES* methodology, with some suggesting that it should be allowed as a regional variation to account for the different peak times in regions such as the WECC.[726] East Texas Cooperatives asks the Commission to require that revenue from hourly firm service be applied as a credit to network service revenue requirements like other point-to-point services. PGP supports the *IES* Method, but recommends that the Commission be open to other approaches.

Reservations, Scheduling, Preemption and Right of First Refusal, Batching

1195. Some commenters support the proposed reservation or scheduling requirements for hourly firm service.[727] Others commenters express concerns regarding, or object to, this aspect of the hourly firm proposal.[728] As discussed below, several commenters suggest modifications to different components of the proposal.

1196. Some commenters state that hourly firm should be a means of selling unused capacity in hours not purchased for longer-term transactions and, as a result, it will be important to establish a sequencing for sales that accomplishes this so that cream skimming does not occur.[729] Tacoma recommends that the Commission establish hourly firm service as the lowest priority in the service request queue. Tacoma also suggests that the Commission limit the purchase of hourly firm in such a way as to assure that the purchase is not an attempt to manipulate a market, such as making the service available only to LSEs, which Tacoma states would ensure that capacity is utilized to meet a real market need.

1197. SPP urges the Commission to apply the same reservation deadline to hourly firm as used for daily firm service in order to make the service easier to administer (and limit the impact on non-firm service). Bonneville also suggests that reservation timing requirements be the same as those for hourly non-firm service and, with respect to competing reservations, hourly firm service be classified as Short-Term Firm. TVA notes that although the scheduling deadline for service is 10 a.m. the day before service is to commence, the NOPR also states that longer-term requests may preempt shorter requests until one hour before the commencement of service. TVA sees an inconsistency in that it appears firm service can be reserved and scheduled after 10 a.m. on the day prior all the way up until one hour before the service is to commence. TVA argues that no service that could preempt the hourly service should be sold after the 10 a.m. day-ahead deadline, and requests that the Commission clarify this ambiguity.

1198. If the Commission requires hourly firm service, Progress Energy requests that it be offered on a day-ahead basis only, as proposed in the NOPR, to allow transmission providers sufficient time to analyze the reliability impacts of the requested hourly firm service. Nevada Companies recommend that any hourly firm service have the same scheduling deadlines as daily firm and that customers not be permitted to submit hourly firm schedules throughout the day. In Nevada Companies' view, this would enable transmission customers to schedule firm transmission only for the part of the day that it is needed while, at the same time, transmission providers would not be overwhelmed with the task of administering the reservation process.

1199. Some recommend that scheduling conform to the existing scheduling practices in each region, such as in the WECC.[730] For its part, MISO argues that the proposed scheduling deadline for hourly firm service is before the deadline for the submittal of the MISO daily firm service, which would require a substantial change to its Energy Markets Tariff, firm service evaluation process, and other firm and non-firm timing requirements. MISO argues that this could adversely affect the current Joint and Common Market Alignment of Business Practices initiative with PJM. Public Power Council offers

[725] *E.g.,* Ameren, EEI, NorthWestern, PGP, and PNM–TNMP.

[726] *E.g.,* Northwest IOUs, Public Power Council, and CREPC.

[727] *E.g.,* Ameren, Duke, NorthWestern, PNM–TNMP, and WAPA.

[728] *E.g.,* Bonneville, Southern, and TVA.

[729] *E.g.,* Public Power Council and Tacoma.

[730] *E.g.,* MidAmerican, Northwest IOUs, Public Power Council, and CREPC.

Bonneville's scheduling timeline as an example in which longer blocks get priority over the shorter blocks within the 10 a.m. to 2 p.m. preschedule-day reservation period, and hourly firm is bought within the day at the same times as hourly non-firm transmission (*i.e.*, up to 20 minutes prior to the delivery hour).

1200. Occidental requests that the Commission change the 10 a.m. day-before scheduling timeline to be as close to real-time as possible. It contends that under the *pro forma* OATT, merchant generators still will be relegated to making non-firm reservations and sales, because the 10 a.m. prior day firm service scheduling timeline would cause them to incur expensive reservations to the sales point, but not be able to have the transaction tagged with source and sink (as required under the NERC tagging procedure), before consummation of the firm hourly transaction. Occidental further contends that the change in scheduling timeline will not be problematic to the transmission providers, particularly if the transaction takes place in a single control area. Occidental also argues that the OATT benefits the transmission provider, which can favor its own or affiliated generation when balancing with other control areas and dispatching in real time.

1201. Bonneville, which has provided hourly firm service since 2002, takes issue with the fact that the Commission proposes that the service would become unconditional only one hour before the commencement of delivery. Bonneville argues that its own timeline, under which hourly firm service becomes unconditional at the close of the preschedule window for the day of delivery (currently, at 2 p.m. of the preschedule day or as soon as practicable thereafter), is superior and should be adopted by the Commission. Bonneville explains that, in its experience, customers place great value on having unconditional firm rights before they reach the real-time scheduling window, and an hour leaves little or no time to make alternative arrangements if the hourly firm reservation is preempted. Finally, Bonneville foresees potential reliability effects if a customer using hourly firm transmission for operating reserves is preempted the hour before delivery, and is unable to make transmission arrangements elsewhere.

1202. Ameren argues that a later request for hourly firm service should not be able to preempt an earlier request, even if it is for a greater number of hours. According to Ameren, this will provide certainty to users of this service since they will know they will not be bumped by other customers using the service.

1203. Duke requests guidance on how long the hourly firm customer has to respond to a competing request. Since hourly firm could be preempted up to an hour before the schedule starts, Duke argues that in many cases there will not be 24 hours available and the scheduling deadline (of 10 a.m. of the day prior to commencement of such service) may have passed. For example, if a pre-confirmed, longer-term, competing request is received just prior to the deadline (one-hour prior to service commencing), Duke questions whether the transmission provider is required to offer the right of first refusal at all.

1204. Joined by TranServ, Duke also requests that the Commission provide guidance on how to administer the right of first refusal when, for example, three different hourly customers have confirmed reservations on a constrained interface for different hours in a day and the transmission provider then receives a pre-confirmed request for daily service on the same path for the same day. Alternatives solutions for this scenario offered by Duke include offering the shorter-term customers simultaneous or consecutive opportunities to exercise the right of first refusal, prohibiting the preemption of multiple overlapping requests, or denying shorter term customers a right of first refusal. Duke recommends NAESB develop appropriate business practice standards after the Commission's decision on this issue.

1205. With the NOPR's potential for adding more complexity with hourly firm service under similar conditions as other short-term firm services, TranServ requests that the Commission either eliminate the conditional nature of short-term firm point-to-point service under the OATT (and the reservation window would be set to not interfere with requests for daily firm service) or allow hourly firm service to be preempted without a right of first refusal.

1206. Duke requests that, whether or not the Commission requires hourly firm service, the Commission clarify how the ''short-term rights of first refusal'' should be implemented in section 13.2(iii) of the OATT, since there already is some lack of clarity with regard to this right for daily, weekly, and monthly service.

1207. Based on its experience, WAPA suggests that the Commission institute limits on the allowable time period in which customers may contact the transmission provider for the purpose of withdrawing an hourly firm request in order to avoid potential ''gaming'' issues that may arise from entities requesting transmission on a pre-scheduled basis and then asking for the request to be withdrawn during real-time. To simplify real-time administration of hourly firm service, WAPA suggests that the Commission explicitly include in the revised *pro forma* OATT a statement waiving the Order No. 638 displacement rules for hourly requests during the hour before the service is to commence.

1208. Several commenters support the Commission's batching proposal.[731] WAPA argues that the proposed limitation on batching hourly firm requests and schedules to within the same day would alleviate the workload issues associated with evaluating individual hourly firm reservations in order to identify conflicting schedules across congested paths.

1209. MidAmerican objects to the batching proposal, arguing that transmission requests should be evaluated in queue order and schedules linked to a specific OASIS request. MISO argues that the batching proposal may interfere with the established protocols for transmission service request processing. In MISO, for example, there is no interface for Available Share of Total Flowgate Capability, which would seem to suggest that batch processing could infringe on the various Commission-approved seams agreements.

1210. Some commenters offer modifications or request clarifications. Bonneville proposes that NAESB develop industry standards for defining and processing batched reservations and schedules. EEI argues that transmission providers who offer hourly firm service should permit their customers to batch multiple requests for service that have the same points of receipt and delivery; are for the same quantity of service, and are for the same day. Otherwise, EEI explains, batching will complicate the ability of the transmission provider to study requests for hourly service. NorthWestern explains that it cannot fully support the Commission's recommendation to allow ''batching'' of requests without a more clear definition of what may be batched and a determination that requests of a longer increment preempt shorter increment requests (*e.g.*, a request for daily service preempts a request for hourly service) regardless of how many hours are batched together.

1211. TranServ states support for the ability to batch requests and schedules for multiple hours of firm service with

[731] *E.g.*, PGP, PNM–TNMP, and WAPA.

varying capacity over the hours. However, with respect to competing requests and the right of first refusal, TranServ suggests that the preempting request must be for a fixed capacity over the term of the request to be considered a competing request. According to TranServ, this would prevent potential gaming by a customer submitting a request for one extra hour at 1 MW to gain priority over another reservation.

Commission Determination

1212. In light of the potential for market disruption and the scheduling complications that would arise from providing hourly firm service, we decline to adopt in the Final Rule the proposal to require transmission providers to offer hourly firm service. While there is some industry support for hourly firm service, we conclude that the downsides associated with requiring transmission providers to offer hourly firm service outweigh the benefits of the proposal due to the significant issues raised by commenters. Commenters opposing mandatory hourly service raise a number of legitimate concerns with respect to the service's potential to adversely affect reliability and create additional complexity and inefficiency in scheduling and administering the right of first refusal. We do not believe that the modifications suggested by commenters supporting the service adequately resolve these concerns. Given regional differences and varying system constraints, a solution that may be appropriate for resolving scheduling, reservation or other issues resulting from hourly firm service on one transmission system may not be appropriate for another transmission system. Moreover, even the commenters supporting the proposal do not demonstrate a clear need for an hourly firm service product. The Commission therefore concludes that requiring hourly firm service is not needed to address undue discrimination, the goal of this rulemaking.

1213. To the extent they deem it appropriate, transmission providers will continue to have the option to propose offering hourly firm service in an FPA section 205 filing with the Commission. Because we are not adopting the mandatory hourly firm service proposal, we believe that the most serious concerns regarding scheduling short-term service and administering the right of first refusal are alleviated. We address scheduling and right of first refusal issues relating to existing services in section V.D.5.b.

3. Rollover Rights

1214. Section 2.2 of the *pro forma* OATT allows existing firm transmission service customers—wholesale requirements and transmission-only customers with contracts of one year or more—the right to continue to take transmission service from the transmission provider when the customer's contract expires. The *pro forma* OATT provides that the transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the transmission provider or elects to purchase capacity from another supplier. This transmission reservation priority for existing firm transmission service customers, which is also referred to as a right of first refusal or a rollover right, is an ongoing right that currently may be exercised at the end of all firm contract terms of one year or longer. A transmission customer must give notice of whether it will exercise its right of first refusal 60 days before the expiration of its service agreement.

1215. In Order No. 888, the Commission provided that, if a transmission customer subject to the rollover right selects a new power supplier that substantially changes the location or direction of its power flows, the customer's right to continue taking service from the transmission provider may be affected by transmission constraints associated with the change.[732] The Commission also provided that a transmission provider may reserve existing capacity for retail native load and network load growth reasonably forecasted within the transmission provider's current planning horizon, but that any capacity so reserved must be posted on the transmission provider's OASIS and made available to others until the capacity is needed for the anticipated network or retail native load use.[733] The Commission also has held that a transmission provider may restrict a right of first refusal based on pre-existing contracts that commence in the future if the transmission provider knows at the time of the execution of the original service agreement that ATC used to serve a customer will be available for only a particular time period, after which time it is already committed to another transmission customer under a previously confirmed transmission request.[734] Once a transmission provider evaluates the impact on its system of serving a long-term firm transmission customer and grants the transmission customer existing capacity, the transmission provider must plan and operate its system with the expectation that it will continue to provide service to the transmission customer should the transmission customer exercise the right of first refusal. If constraints arise after a transmission provider enters into a long-term agreement with the transmission customer (and that agreement does not contain an allowed restriction on the transmission customer's right of first refusal), the obligation is on the transmission provider to either curtail service to all affected customers or build more capacity to relieve the constraint.[735] A transmission provider is obligated to curtail service pursuant to its OATT or expand its system when its system becomes constrained such that it cannot satisfy existing transmission customers, including the exercise of their rollover rights, because it should have planned and operated its system with the expectation that each long-term firm transmission customer will exercise its rollover rights.[736]

1216. If a transmission provider's transmission system cannot accommodate all of the requests for transmission service at the end of the contract term, the existing long-term transmission customer must agree to match the rate offered by the potential customer, up to the transmission provider's maximum rate, and to accept a contract term at least as long as that offered by the potential customer. However, a competitor's offer does not have to be ''substantially similar in all respects'' to the existing transmission customer's.[737]

NOPR Proposal

1217. In the NOPR, the Commission proposed to revise the right of first refusal provision in the *pro forma* OATT to apply to firm wholesale requirements and transmission-only contracts that have a minimum term of five years, rather than the current minimum term of one year. In addition, a transmission customer under a rollover agreement would be required to provide notice of whether it intended to exercise its right of first refusal no less than one year prior to the expiration of its contract, rather than the current 60 days. The Commission proposed to maintain the requirement that an

[732] Order No. 888 at 31,665 n.176.

[733] *Id.* at 31,694.

[734] *E.g., Southwest Power Pool, Inc.,* 109 FERC ¶ 61,041 at P 6 (2004).

[735] *Id.* at P 9.

[736] *Id.*

[737] *Idaho Power Co.* v. *FERC,* 312 F.3d 454, 462 (D.C. Cir. 2002).

existing transmission customer match competing offers as to term and rate. The Commission discussed whether native load restrictions should be reevaluated with each rollover and, if so, whether native load should then be required to compete with rollover customers for the capacity. The Commission also asked for comment on whether there is a sufficiently clear, consistent, and transparent method that could be implemented on a generic basis to address the need for a transmission provider to demonstrate its forecast of native load growth and its effect on capacity reserved by rollover customers. The rollover reforms were proposed to be effective as to new transmission contracts upon Commission acceptance of the transmission provider's coordinated and regional planning process required by the Final Rule, with existing rollover contracts becoming subject to the new rules on the first rollover date after the effective date of the revisions.

a. Five-Year Minimum Contract Term

Comments

1218. Many commenters support the increase in the contract term eligible for a rollover right.[738] These commenters support the increase to five years based largely on the Commission's rationale for proposing it, *i.e.*, an increase to five years would encourage longer-term use of the grid and assist in long-term planning. Many also point out that a longer minimum term reduces the universe of contracts transmission providers must assume will exist in perpetuity, thereby increasing certainty and reducing speculation. These commenters also argue that rollover reform will improve reliability and provide increased revenues to perform upgrades. Some also argue that this is consistent with the native load protections in new section 217 of the FPA.

1219. E.ON, for example, notes that system expansions may have been limited in the past because transmission providers did not want to commit resources to accommodate a service guaranteed for only one year, and Xcel and TVA note that the increase in term should encourage investment and expansion of the grid by providing improved certainty of cost recovery. EEI stresses that there is no single minimum rollover term that works for all parties, as power purchase contract terms vary and some state planning obligations require purchases for longer or fewer than five years, but that five years represents a reasonable balance. Southern emphasizes that the reforms should also improve reliability, promote the provision of service to native load transmission customers, and increase market efficiencies by releasing transmission capacity to the market. In its reply, Southern expresses its belief that the current policy of requiring transmission planners to assume that all agreements having a minimum term of one year will continue taking service in perpetuity threatens reliability. In Southern's view, this policy results in planning that is based on speculation and guesswork that can signal a need for inappropriate and expensive transmission upgrades and mask the need for appropriate expansion.

1220. However, several modifications and clarifications were sought by some commenters before they could agree to an increase in the minimum term to five years. APPA, Sacramento, and TAPS contend that transmission customers making this long-term commitment should be permitted to change their designated resources and receipt points as their power supply needs change.[739] APPA also asserts that transmission customers that agree to a five-year contract term should not be forced to compete with other transmission customers for firm capacity whenever their contracts come up for renewal. Without such assurances of continued service, APPA argues that the Commission's proposals would not comport with section 217 of the FPA.[740]

1221. In order to further ensure continued service, TAPS seeks the following modifications: Transmission providers should be required to redispatch if necessary to accept a ''reasonably foreseeable'' and timely designated network resource with costs shared on a load ratio basis; transmission providers should be required to offer cost-based sales to embedded transmission-dependent utilities that cannot reach alternative suppliers; and exceptions should be permitted to the five-year minimum term and matching exposure for small embedded transmission-dependent utilities and full or near-full requirements customers to ensure a continued right to service. Additionally, TAPS asserts that the minimum rollover in the absence of a competing request should be one year, rather than five.

1222. TDU Systems, which generally opposes the increase to five years, believes that the Commission should clarify that rollover customers retain their rights to transmission capacity in the event of competing bids from either the transmission provider or another transmission customer if the rollover customer matches up to a five-year contract term. Lastly, Seattle is concerned that with a five-year minimum, the risk in multi-segmented transmission transactions of one segment being undone by refusal of another is increased. Seattle suggests that acceptance and confirmation of one segment be made contingent on coordinated acceptance and confirmation on all other required segments.

1223. In its reply to the arguments that rollover rights should be extended to accommodate service at new receipt or delivery points, EEI argues that this would allow a rollover customer to have priority over higher-queued customers on transmission paths other than the path over which the rollover customer is currently taking service, even if the new service would have different impacts on the transmission system. EEI argues that such service would be new service and not a rollover of existing service. EEI also urges the Commission to reject TAPS's assertion that it should require the transmission provider to accept rollover customers' designations of any network resources that are reasonably foreseeable and to redispatch its system if necessary to accommodate that resource, because among other things this would require providers to build the transmission system with sufficient redundancy to permit any customer to take service from any resource. Moreover, EEI argues that TAPS does not provide any suggestion as to what should be considered a reasonably foreseeable resource and that sharing costs on a load ratio basis would result in eighty to ninety percent of the redispatch costs being borne by the transmission provider's native load customers.

1224. EEI also argues in its reply that TAPS's proposal to exempt all small customers from the five-year minimum term would interfere with transmission providers' ability to plan their systems to meet their customers' needs, as the

[738] *E.g.,* APPA, Barrick Reply, Bonneville, Community Power Alliance, Constellation, Dominion, Duke, EEI, Entegra, Entergy, E.ON, FirstEnergy, Great Northern, Imperial, Indianapolis Power Reply, LPPC, LDWP, MidAmerican, MISO, MISO Transmission Owners, Nevada Commission, Nevada Companies, North Carolina Commission Reply, Northwest IOUs, NorthWestern, NPPD, PGP, Pinnacle, PNM–TNMP, Progress Energy, Public Power Council, Sacramento, Salt River, Santa Clara, Seattle, South Carolina E&G, Southern, SPP, Tacoma, TAPS, TransServ, TVA, Utah Municipals, and Xcel. The Commission notes that several of these commenters have conditioned or qualified their support on the adoption of a number of modifications, which will be discussed below.

[739] *See also* TDU Systems Reply.

[740] *See also* NCEMC and Arkansas Municipal (opposing the increase in the minimum term to five years).

aggregated loads of several small customers can have a substantial impact on the system. EEI contends that TAPS's proposal to exempt all full and near-full requirements customers is also unreasonable, as the transmission provider would be forced to provide preferential service to certain groups of customers. As for the proposal to allow customers to exercise rollover rights with only one-year contracts if there is no competing request, EEI contends there is no need for a rollover if there is no competing request, since there is enough capacity for all and the transmission provider will grant the customer's new request for service for one year.[741]

1225. The increase in the minimum contract term eligible for a rollover right was opposed outright by several commenters for a variety of reasons.[742] Many of these commenters oppose the increase to five years because they claim it is difficult under current market conditions to secure a five-year power supply agreement to underpin a five-year transmission contract, particularly in organized markets where the focus is on spot transactions or where the grid is very weak.[743] They also argue that changes in the market (*e.g.,* fuel costs) could significantly change the options available to customers within a five-year period and that a service extension of less than five years may be needed to manage delays in generation construction or some other unforeseeable event. TDU Systems urge the Commission to require any transmission provider seeking an increase in the minimum contract term to demonstrate that sufficient economic power supplies are available under longer-term contracts. EEI replies that such an approach would be inconsistent with the separation of functions between generation and transmission.

1226. Some commenters also argue that five years is incompatible with retail procurement processes in some states, such as Illinois and New Jersey, which they assert limit power supply agreements to three years.[744] AWEA and PPM suggest that the Commission increase the minimum term to three years, because five years is beyond the term for many shorter-term power sales transactions and it would be cost prohibitive to lock up service for five years. Manitoba Hydro suggests a two- to three-year minimum term and that guaranteed redirects be permitted. Constellation, while generally supportive of a five-year minimum term, would prefer a three-year minimum term because it says three years is more closely aligned with much of the commercial activity in the energy commodity markets. Wisconsin Electric supports the current one-year term, but proposes three years as an alternative. In its reply, Duke indicates that it would support a three-year minimum term for rollover, but only if the notice period is required to match project lead time.

1227. In their replies, several commenters dispute the assertion that customers may not be able to obtain generation supplies for five-year periods. They contend that generators in a competitive market will have to offer five-year contracts or risk losing their sales if LSEs begin requesting five-year contract terms in order to obtain rollover rights.[745] SPP states on reply that it has not been its experience that suppliers have refused to enter into power supply agreements in excess of three years. EEI also argues that, even if a transmission customer has to accept the risk that its term of service exceeds the term of its power purchase in order to obtain rollover rights, the cost of the transmission service that is at risk is small in comparison to the cost of the power because the cost of transmission service is only a small portion of the delivered price of energy. EEI and Bonneville also note in their replies that unneeded transmission service can be sold in the secondary market.

1228. NCEMC opposes the increase in contract term because it would inhibit the ability to pursue its prudent portfolio approach to mitigate price risks by providing for a mix of shorter and longer-term power supply contracts. If the Commission increases the minimum term, NCEMC argues that all existing rollover contracts should be grandfathered. EPSA also believes that existing one-year contracts should be grandfathered, otherwise it argues that market participants that relied on the current policy will be harmed. In its reply, EEI urges the Commission to reject EPSA's proposal that all currently effective one-year power supply contracts be grandfathered because, in EEI's view, it would interfere with good utility planning. EEI also argues that extending the minimum term to five years does not abrogate a customer's power supply contract because transmission and supply are unbundled and, therefore, changing the terms of transmission service does not interfere with contract rights under power sales agreements.

1229. Exelon argues that limiting rollover rights to contracts that are five years or greater will discriminate against merchant generators that do not have load linked to generation, lead to stranded generation investments that were based on the current rules, and unfairly advantage local utilities wanting to build their own generation as opposed to seeking competitive alternatives. Exelon suggests that an approach similar to that utilized in PJM be adopted, in which PJM evaluates new requests for service that cannot be granted without utilizing an existing customer's service by notifying the existing customer and requiring it to match the new request within thirty days or release the service. PJM explains further that its approach would allow transmission customers two rollover options: long-term service for less than five years with no rollover right, or service for one year with indefinite rollover rights conditioned on either future limitations or an agreement to pay for necessary upgrades to maintain the rollover. In its reply, TAPS opposes the PJM approach stating that it would invite discrimination by transmission owners.

1230. Other commenters that oppose the increase to five years assert that they are already long-term customers that simply take service year-to-year and should therefore already be included in planning, based on the fact that they are either a generator or load and cannot simply pick up and leave the system.[746] Several other commenters likewise oppose the increase to five years because they do not believe that it will result in an increase in long-term contracting and planning as suggested by the Commission.[747] For example, Williams notes that it currently has a ten-year transmission contract and argues that its transmission provider has done nothing to improve the grid in its area. TransAlta believes that a five-year minimum contract term will limit market participation to deep-pocketed market participants who can afford long

[741] In their replies, Entergy, MidAmerican, and Progress Energy note many of these same concerns.

[742] *E.g.,* Alberta Intervenors, Alcoa, Ameren, AMP-Ohio, Arkansas Municipal, AWEA, Dynegy Reply, Eastern North Carolina, EPSA, Exelon, Fayetteville, Manitoba Hydro, Morgan Stanley, NCEMC, NRECA, MISO/PJM States, PJM, Powerex, PPM, Reliant, TDU Systems, TransAlta, Williams, and Wisconsin Electric.

[743] *E.g.,* Alcoa, AMP-Ohio, Arkansas Municipal, AWEA, Eastern North Carolina, EPSA, Exelon, Fayetteville, Manitoba Hydro, NCEMC, NRECA, MISO/PJM States, Reliant, TDU Systems, and Wisconsin Electric. TAPS also notes the difficulties, particularly for small transmission-dependent utilities, of locking in a five-year supply contract a year in advance of rollover.

[744] *E.g.,* EPSA, Exelon, Reliant, and MISO/PJM States.

[745] *E.g.,* EEI Reply and Southern Reply.

[746] *e.g.,* Morgan Stanley and Manitoba Hydro.

[747] *e.g.,* Alberta Intervenors, TransAlta, and Williams.

contracts. TransAlta also believes that the current option to contract for just one year and obtain a rollover right is often the benefit that prompts market participants to buy yearly service instead of shorter-term products and, therefore, is an incentive to purchase longer-term service. Alberta Intervenors believe that a longer minimum term will provide a disincentive for long-term trading since the increased time commitment of five years will significantly increase the trading party's risk.[748] The Organizations of MISO and PJM States believe that the current rollover policy generally results in an increase in investment in transmission and is only detrimental if service is terminated and the capacity goes unused.

Commission Determination

1231. The Commission finds that the current rollover policy is no longer just, reasonable, and not unduly discriminatory. The rights and obligations of a rollover customer should bear a rational relationship to the planning and construction obligations imposed on the transmission provider by the rollover rights. We find, for the reasons explained below, that the current policy no longer meets this standard and that a five-year term will ensure greater consistency between the rights and obligations of customers and the corresponding planning and construction obligations of transmission providers. We also believe that an increase to a five-year term is consistent with the native load protections contained in new section 217 of the FPA, primarily because requiring longer-term agreements ensures that the rollover right is used by transmission customers with long-term obligations to purchase capacity.[749] Accordingly, the Commission adopts a five-year minimum contract term in order for a customer to be eligible for a rollover right. At the end of its initial five-year contract term, a transmission customer must, within the one-year notice period (discussed more fully below), agree to another five-year contract term or match any longer-term competing request in order to be eligible for a subsequent rollover.

1232. Our decision to adopt a five-year minimum term will remedy many of the problems associated with the current policy. Under our current policy, a customer can secure transmission service for one year and, in so doing, require the transmission provider to plan and upgrade its system on the assumption the rollover right will be continually renewed. For example, if a transmission provider's planning horizon is 10 years, a one-year reservation would require the transmission provider to plan and upgrade the system as if the customer had purchased 10 years' service (*i.e.*, would exercise its rollover right every year during that 10-year period). Because of this, the customer receives a guarantee of service beyond what it has contracted to pay for and the transmission provider must plan for service that may not actually be used.

1233. By failing to link the customer's rights and obligations with those of the transmission provider, the current policy can have several detrimental effects. For example, it requires the transmission provider to plan and construct facilities that may not be necessary to serve load. Given the difficulty of siting new transmission, it is inappropriate to require transmission providers to use finite resources to finance and construct facilities that may not be necessary. Additionally, the current policy harms OATT customers by allowing rollover customers to tie up capacity that may be needed by other customers. This is because the current policy allows a rollover customer to lock up existing capacity, regardless of whether the rollover customer intends to use that capacity. This reduces the availability of existing capacity for other customers and, in turn, reduces competitive alternatives for customers.

1234. Some commenters have argued that the Commission should use a shorter period, such as three years, that is more aligned with auctions in retail access markets or existing commercial practices. We disagree. The purpose of our reform of the rollover rights policy is to ensure that the rights and obligations of the customer are better aligned with the planning and construction obligations of the transmission provider. It is not to link the term of the rollover right to any particular commercial practice in any particular region. We do not believe that such a policy could be fairly implemented in any event. Commercial practices vary between the regions and change over time, and it would therefore be impractical to tailor the rollover rights in the OATT to the varying commercial practices across the country.

1235. We also do not believe that adopting a five-year minimum term will have an adverse effect on participation in retail auctions that use three-year solicitations. At the outset, we note that retail auctions use solicitations of varying length and, hence, the fact that some states may use three-year auctions does not provide a basis to establish a generic standard for rollover rights under the OATT. Some states use shorter term auctions (*e.g.*, one year) and, as indicated, we cannot reasonably tailor an OATT rollover obligation to the varying commercial practices across the country. We also do not believe that our policy will have an adverse effect on any such auctions. The winners in a retail solicitation are determined anew in each auction, based on the bids submitted in that auction. A prospective bidder therefore does not need a "rollover right" to compete in an auction. It only needs transmission service over the term of the solicitation (*e.g.*, three years). The fact that it may not have an automatic right to transmission capacity in the next auction simply places it on the same footing as any other bidder.

1236. In response to those commenters who argue that transmission customers making this long-term commitment must also be permitted to change their designated resources and receipt points as their power supply needs change, we believe that such an approach is unworkable. Allowing rollover customers to change their designated resources and receipt points in this manner would inappropriately result in rollover customers having priority over other transmission customers in the queue that may have already requested service over a given transmission path. This could result in substantial disruptions to transmission service to higher-queued customers requesting long-term service over these paths.[750] Moreover, transmission customers are not currently guaranteed the ability to turn to other suppliers at other designated resources and receipt points and, therefore, we do not understand how simply increasing the minimum contract term to five years should

[748] *See also* Morgan Stanley.

[749] *See* EPAct 2005 sec. 1233(a) (to be codified at section 217(b)(4) of the FPA, 16 U.S.C. 824q), which provides that "[t]he Commission shall exercise the authority of the Commission under [the FPA] in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long term basis for long term power supply arrangements made, or planned, to meet such needs."

[750] We agree with EEI that requiring transmission providers to ensure rollover customers the ability to change their designated resources and receipt points without disrupting service to other customers would, taken to its logical conclusion, require transmission providers to construct the transmission system with sufficient redundancy to permit any customer to take service from any resource.

necessarily result in allowing transmission customers this increased flexibility. Likewise, we do not understand why an increase in the minimum contract term should result, as argued by APPA, TAPS, and others, in a transmission customer not having to compete with other transmission customers for firm capacity whenever its contract comes up for renewal. As discussed below, we will continue to require transmission customers to match competing requests for service as to term and rate, ensuring that transmission customers that value the service the most receive it.

1237. We reject TAPS' proposal to exempt all small customers from the five-year minimum, since this would interfere with transmission providers' ability to plan their systems to meet their customers' needs. As EEI points out, the aggregated loads of several small customers can have a substantial impact on the system. We therefore believe it would be inappropriate to categorically exempt small customers. We also reject TAPS' proposal to exempt all full and near-full requirements customers, because it would force transmission providers to provide preferential service to certain groups of customers. Additionally, we reject TAPS' proposal to allow customers to exercise rollover rights with only one-year contracts if there is no competing request. Without a competing request, a rollover right is not necessary in order to continue service as long as capacity remains available. Additionally, allowing a rollover for a one-year contract would continue to impose planning and construction obligations on the transmission provider that bear no reasonable relation to the rights and obligations of the rollover rights customer. We further reject TDU Systems' proposal that transmission providers demonstrate the availability of long-term supplies before moving to a five-year term. To do so would effectively require transmission providers to engage in the business of procuring supplies for their transmission customers, which is clearly outside the scope of their obligation to provide transmission service, and could implicate Standards of Conduct issues.

1238. We also reject the proposal of EPSA and others that all currently effective one-year power supply contracts be grandfathered because this would disrupt transmission planning. For example, such an approach would require that a large portion of existing capacity be planned for on a significantly different timeline than that subject to the reformed rollover right. This also would detract from one of the primary goals of rollover reform, which is to improve transmission planning and encourage longer-term contracting. As discussed below, existing transmission contracts will be permitted to roll over under their existing terms until the first such rollover opportunity following the effectiveness of the reforms required by this Final Rule.

1239. Lastly, we note that many of the reforms adopted elsewhere in this Final Rule will be beneficial to customers that no longer receive rollover rights, as well as to customers with rollover rights that wish to use their rollover rights to turn to alternative suppliers using different transmission paths. First, greater consistency and transparency in ATC calculations will provide greater assurance of nondiscriminatory access to existing transmission capacity. Second, our reforms relating to conditional firm and redispatch service will help to maximize the use of existing capacity, consistent with reliability, thereby providing customers without rollover rights greater flexibility to purchase existing transmission capacity. Third, our clarifications regarding our policy on redirects should improve the ability of transmission customers to redirect their service to new receipt or delivery points. Fourth, lifting the price cap on reassigned transmission capacity should assist transmission customers in reassigning any capacity that may not be needed on a given path because of a change in suppliers that requires service over new transmission paths. This will also necessarily result in the unneeded capacity being freed up for use by other transmission customers, thereby further assisting them in obtaining capacity that they need to access alternative suppliers. Lastly, and most importantly, greater openness and coordination in transmission planning should provide all customers better information regarding future resource options and access to competitive alternatives. We also believe that improved transmission planning should help to address allegations made by certain transmission customers (*e.g.*, Williams) that even though they have signed up for ten years of service, they have not seen their needs planned for adequately.

b. One-Year Notice Provision

Comments

1240. Many commenters support an increase in the notice period to one year or some other greater time period.[751] Most support the increase based on the argument that the current 60-day notice period makes it very difficult to plan the system, because transmission providers often do not know until 60 days before the end of a contract whether a transmission customer will roll over its service, resulting in potential overbuilding of the system (*e.g.*, because a transmission provider must plan its system assuming a transmission customer will roll over but sometimes it does not). They also argue that it is difficult to re-market capacity in only 60 days if rollover is not sought and that potential transmission customers are often unnecessarily turned away because transmission providers are unaware of the availability of capacity until 60 days before the end of a contract subject to a rollover right. In general, these commenters view a one-year notice period as an improvement. However, many of these same commenters do not believe one-year notice is appropriate if the transmission provider must construct facilities to accommodate a rollover and, therefore, the notice should instead be tied to the start date for any necessary upgrades.[752]

1241. EEI, for example, believes that notice should be tied to the start date of any necessary transmission upgrades, because the transmission provider may be left with stranded transmission capacity if it must begin construction on upgrades necessary to accommodate a rollover before the transmission customer has even indicated whether it will in fact seek a rollover. EEI also argues that a competing customer could be required to pay an incremental rate for network upgrades that could have been avoided if the rollover customer had provided earlier notice of its intention not to seek a rollover. EEI further contends that some state commissions will not allow upgrades where there is only the potential for a rollover. Finally, EEI states that a one-year notice period does not ensure that the transmission provider will be able to re-market the capacity, forcing other

[751] *E.g.*, Ameren, Barrick Reply, Bonneville, Community Power Alliance, Constellation, Dominion, Duke, East Texas Cooperatives, EEI, E.ON, Entegra, Entergy, FirstEnergy, Great Northern, Imperial, LDWP, LPPC, MidAmerican, MISO, MISO Transmission Owners, Nevada Commission, Nevada Companies, North Carolina Commission Reply, NorthWestern, Northwest IOUs, NRECA, PGP, Pinnacle, PNM–TNMP, Progress Energy, Public Power Council, Salt River, Santa Clara, Southern, South Carolina E&G, SPP, Tacoma, TranServ, TVA, Utah Municipals, and Xcel. Both APPA and TAPS support a one-year notice provision, but only on the condition that the clarifications and modifications they suggest are made.

[752] *E.g.*, Barrick Reply, Duke, EEI, Entergy, Indianapolis Power Reply, LPPC, Nevada Commission, Nevada Companies, Pinnacle, Progress Energy, South Carolina E&G Reply, Southern, and TVA.

transmission customers to bear the increased costs associated with the newly constructed transmission facilities. EEI proposes that a date be included in the initial service agreement by which the transmission customer must exercise its rollover rights if upgrades are needed to accommodate the rollover. If there is a pre-confirmed competing request or newly projected growth in native load, EEI suggests that the rollover customer must exercise its rollover and match by the later of the project start date for any new transmission facilities needed or 60 days after the transmission provider notifies the transmission customer of the competing request.[753] Additionally, if more than one-year notice is required because of the need for upgrades, EEI proposes that the transmission provider be required to notify the transmission customer if subsequent events delay the project start date, in which case the notice period would be revised. EEI asserts that any disputes can be dealt with by protesting the filing of an unexecuted agreement. EEI stresses that better, more inclusive planning, and more transparent ATC calculations, will provide transmission customers with greater assurances that project start dates are accurate.

1242. Southern suggests that partial rollover be permitted if notice is not given in time for construction of an upgrade needed to provide full service. Duke, Nevada Commission, and Southern suggest that providing for one-year notice without a link to the start date for any upgrades falls short of the native load protections found in section 217 of the FPA. As an alternative, the Nevada Commission suggests tying the notice requirement to the amount of capacity subject to rollover, *i.e.*, below a certain threshold, one year would be deemed *per se* sufficient.

1243. APPA argues in reply that many customers may not know even one year in advance if they will have firm power supplies under contract that would enable them to roll over their corresponding firm transmission agreement and, therefore, requiring them to exercise their rollover rights even earlier in the contract term would only exacerbate an already impossible situation. In their replies, NRECA, TAPS, TDU Systems, and Utah Municipals urge the Commission to reject the recommendation that notice periods be expanded to be commensurate with construction lead times. They argue, among other things, that LSE transmission customers need a reasonable amount of certainty so that they may plan their power supply arrangements without fear that they may become unraveled due to unforeseeable circumstances. Utah Municipals also assert that the proffered justification for the proposal—to prevent overbuilding—is questionable at best as even the current policy which requires only a one-year contract minimum for rollover and 60-days notice has not resulted in wasteful overbuilding of the system. TDU Systems also point out that under section 28.2 of the *pro forma* OATT, transmission providers should be planning and expanding their systems to accommodate their network customers' current and future needs.

1244. The one-year notice provision is opposed by several commenters, who argue that having to give one-year notice constitutes an undue burden.[754] In general, these commenters argue that under current market conditions, transmission customers do not typically renew supply contracts one year in advance of expiration.[755] Alberta Intervenors argue that a one-year notice provision does not aid in re-marketing capacity, as any unused long-term firm service is already re-marketed as short-term firm or non-firm service. Alberta Intervenors also argue that the increased lead time increases risk and creates uncertainty making it less likely that customers will enter into long-term contracts. EPSA and Exelon suggest a flexible notice rule that depends on the length of the underlying contract or requiring more than 60-days notice if there is insufficient capacity for a new long-term firm transmission service request, as is done in PJM. They also suggest PJM's approach whereby a transmission customer must inform PJM whether it will roll over within thirty days of being notified of a competing request. PPM and Wisconsin Electric suggest a six-month notice period, which complements their alternative suggestion of a three-year minimum contract term.

Commission Determination

1245. The Commission finds that the current 60-day notice period should be modified to reflect the longer term (five years) of the rollover rights. Currently, a customer with a one-year rollover right has 60 days to provide notice of whether it intends to rollover its capacity. This 60-day period was reasonable for a rollover right of short duration (one year), but it is no longer reasonable for a rollover right with a minimum five-year term.

1246. In selecting a new notice period, the Commission has attempted to balance the circumstances faced by customers in renewing power supply contracts and the interests of transmission providers in attempting to plan their system. The Commission recognizes that no single notice period can perfectly balance these considerations, but chooses the one-year notice period as most appropriate under the circumstances. Given that the minimum rollover term has been lengthened to five years, it is reasonable to expect that customers will consider renewing such long term obligations in advance of 60 days prior to the expiration of their current obligation. We do not believe it is reasonable to fashion our notice period for customers that wait until the last minute to evaluate whether to extend their long-term contracts.

1247. Many transmission providers argue that a one-year notice period is too short because it is not consistent with the transmission provider's planning horizon. We disagree. The Commission is extending the minimum term for rollover rights to five years to ensure greater consistency between the customer's rights and obligations and the planning and construction obligations of the transmission provider. We believe that this modification satisfies the principal concerns of transmission providers regarding the current policy on rollover rights. We recognize that a one-year notice period is shorter than the typical planning horizon, but we decline to extend the notice period to a time that coincides with the typical planning horizon or the time it takes to construct new facilities. Doing so would effectively eliminate rollover rights altogether, given that the resulting notice period could be three-to-five years. We do not believe it is reasonable to expect customers to have decided on new sources of supply three years in advance of the expiration of their current contracts. We therefore find that a one-year notice period most appropriately balances the interests of customers and transmission providers.

c. Matching and Rollover Restrictions Based On Native and Network Load Growth

Comments

1248. As noted above, the Commission proposed to maintain the requirement that an existing rollover

[753] Ameren, Pinnacle, Southern, and TranServ agree that the submission of a competing request should trigger an accelerated timeline for the original customer to exercise or release its rollover rights.

[754] *E.g.*, Alberta Intervenors, Alcoa, Arkansas Municipal, EPSA, Exelon, Manitoba Hydro, Morgan Stanley, PPM, TransAlta, Williams, and Wisconsin Electric.

[755] *E.g.*, Arkansas Municipal, Williams, and Wisconsin Electric.

transmission customer match competing offers as to term and rate. Some commenters argue that a competing customer be required to execute a contingent service agreement that becomes effective if the rollover customer does not match.[756] Given the increase in the minimum contract term to five years in order to be eligible for a rollover right, TAPS argues that matching must be structured to recognize that a network customer must extend its power supply by at lease five years as well, in order to match a competing point-to-point customer that can simply extend its reservation. To ensure that network customers are not disadvantaged by matching, TAPS suggests that the Commission restrict reservations qualified to compete against a network customer's reservation to customers with long-term power contracts, so they are on more equal footing with network customers. TAPS also proposes a cut-off for requests with which the network customer will need to compete, such as three months prior to when the network customer exercises its rollover right, so that the network customer can structure its power supply commitments with some degree of advance knowledge of the competing requests. In its reply, Bonneville suggests allowing network transmission customers to compete based on the duration of their network transmission service request rather than on the duration of their resource commitments. As such, the transmission provider would assume that existing designated resources would continue to be used after the rollover unless informed otherwise.

1249. The Commission also discussed in the NOPR whether native load restrictions should be reevaluated with each rollover and, if so, whether native load should then be required to compete with rollover customers for the capacity. Several commenters argue that a transmission provider's native and network loads should not be forced to compete with other transmission customers, as opposed to allowing the transmission provider to continue to reserve capacity for its native and network load at the time of granting a rollover.[757] Most also stress that requiring a transmission provider to compete would violate the native load protections in section 217 of the FPA. LDWP contends that there should be no limitation on a transmission provider's right to recall capacity based on revised forecasts of native load growth.

1250. APPA contends on reply that transmission customers could find it very difficult to line up a new firm power supply of a term long enough to match the power supply arrangements of its vertically-integrated investor-owned transmission provider (which is likely to have owned, rate-based generation in its power supply portfolio and, therefore, could agree to a very long-term transmission agreement). TDU Systems argue that transmission providers should be forced to compete for capacity and that this is, in fact, required by section 217 of the FPA, as the native load preference does not distinguish between the retail native loads of transmission providers and the native loads of other LSEs dependent on their systems. Powerex and PPM also support requiring transmission providers to compete. NorthWestern and Southern support requiring transmission providers to compete, but only when a restriction is not included in the original agreement. APPA also notes in its reply comments that, if Southern included LSEs' loads in its transmission planning and construction program along with its own native load, there would be no need to reclaim the LSEs' capacity at the close of the initial contract term or the renewal terms.

1251. Several commenters also addressed the Commission's request for comment on whether there is a sufficiently clear, consistent, and transparent method that could be implemented on a generic basis to address the need for a transmission provider to demonstrate its forecast of native load growth and its effect on capacity reserved by rollover customers. Many of these commenters support the development of a clear and transparent method for demonstrating native load growth.[758] Some commenters point to the need for accurate and transparent ATC calculations to aid in this process.[759] If the transmission provider's calculation of ATC is consistent with the requirements the Commission adopts in this proceeding yet there is insufficient capacity to accommodate the customer's rollover, EEI recommends that the provider may include in the service agreement a limitation of rollover rights. AWEA recommends that transmission providers adopt the same transparent and consistent methods used to compute the Existing Transmission Capacity component of ATC to develop native load growth reservations that support rollover restrictions. AWEA, NorthWestern, and TAPS suggest posting forecast information on the OASIS, and TAPS goes on to stress that this information should be included in state planning documents as well as the transmission provider's coordinated and regional planning process. EPSA stresses that native load capacity must follow native load and not only be made available for the transmission provider and its affiliates. EPSA believes this is required by the native load protections found in FPA section 217.

1252. Duke asks the Commission to address the possibility that capacity subject to a rollover right might be needed to serve native load outside of the ten-year planning horizon. The Nevada Commission and Southern suggest that the Commission give deference to state resource planning processes in attempting to verify native load growth forecasts. Southern also asks that the Commission clarify that rollover rights can be restricted based on rollover rights belonging to higher-queued transmission customers. If transmission studies show no problems without the presence of a rollover, but then problems are identified with the rollover included, Southern contends that placing a corresponding limitation in the service agreement would be appropriate. Pinnacle requests clarification that when rollover rights are restricted based on native load growth, the transmission customer must pay for upgrades to continue its service.

1253. Several commenters also suggest that transmission providers should be permitted to evaluate rollover restrictions at the time of each rollover.[760] These commenters argue that it is impossible to identify all potential limitations upfront as system conditions change in unforeseeable ways (*e.g.*, fluctuations in fuel prices can change dispatch decisions). They also argue that allowing a re-evaluation is consistent with the native load protections in FPA section 217.

1254. In its reply, TAPS argues that a transmission provider should not be permitted to avoid its planning and expansion obligations by treating load growth not anticipated and documented in the original service agreement as a competing request to be matched. TAPS points out that section 217 of the FPA treats all LSEs—whether they are transmission providers or transmission-dependent utilities—the same, without

[756] *E.g.*, MidAmerican and Powerex.

[757] *E.g.*, Allegheny, Entergy, FirstEnergy, Imperial, Nevada Companies, Progress Energy, Salt River, Santa Clara, and Seattle.

[758] *E.g.*, AWEA, Duke, EEI, Entergy, EPSA, Imperial, Nevada Commission, Powerex, Salt River, Seattle, South Carolina E&G, Southern, SPP Reply, and TAPS.

[759] *E.g.*, AWEA, EEI, EPSA, and MISO.

[760] *E.g.*, Nevada Companies, South Carolina E&G, and Southern.

distinction, and therefore provides no basis to allow one LSE to claim transmission rights currently used by another LSE.[761] Lastly, TAPS argues that when a provider is reclaiming capacity for load growth reserved in the initial service agreement, rollover customers should be allowed to match the request, thereby imposing an additional requirement on the provider.

Commission Determination

1255. The Commission will not adopt any changes to its matching policies at this time. At the time of rollover of their contracts, transmission customers will continue to be required to match competing requests for service as to term and rate in order to roll over their service. This preserves the current policy goal of providing a mechanism for awarding capacity to those who value it most, as well as providing for a tie-breaking mechanism when needed that gives priority to existing customers so that they may continue to receive transmission service.[762] Absent the requirement that the customer match the contract term of a competing request, transmission providers could be forced to enter into shorter-term arrangements that could be detrimental from both an operational standpoint (*i.e.*, system planning) and a financial standpoint.[763] We clarify, however, that transmission customers must also enter into a transmission contract of at least five years in order to obtain a subsequent rollover right in the absence of a competing request for a longer term.

1256. The Commission will continue to require rollover restrictions based on reasonable forecasts of native load growth or preexisting contracts that commence in the future to be included in the initial transmission service agreement. This will remain the only appropriate way to restrict a rollover right. We also will continue to evaluate a transmission provider's native load growth forecasts on a case-by-case basis, as no commenter has provided us with a sufficiently clear, consistent, and transparent method that could be implemented on a generic basis that ensures that the demonstration of native load growth is accurate and is tied to a need for the specific capacity reserved by a rollover customer.[764] Because we will continue to require rollover restrictions to be included in the initial transmission service agreement, we necessarily reject the suggestion that transmission providers be permitted to restudy for rollover restrictions at the time of each rollover. Accordingly, it is unnecessary for us to address whether it would be appropriate for a transmission provider's native or network load to compete with a rollover customer if a new study at the time of the rollover indicated a native or network need for the capacity.

1257. In response to the suggestions of some commenters, we believe that consideration should be given in our case-by-case evaluations of native load growth forecasts to state-approved integrated resource plans that show a native load need for the capacity.[765] Moreover, we believe that the ATC and planning reforms that we are adopting in this Final Rule will provide greater transparency and assurance that transmission providers' forecasts of native load growth are accurate. We emphasize that we expect the forecasts utilized in transmission planning to be consistent with the forecasts utilized to support a rollover restriction. Lastly, the coordinated and regional planning process required by this Final Rule is designed to improve the availability of transmission service by, among other things, increasing transparency and providing customers a meaningful opportunity to participate in the planning process. Accordingly, we believe that improved planning should help to reduce the need to restrict rollovers in the future.

d. Other Issues

Comments

1258. A number of comments relate to the applicability of the rollover-related reforms to RTOs and ISOs. CAISO asks the Commission to confirm that the rollover reforms do not apply to CAISO as its current tariff does not have such a provision and rollover is, in fact, incompatible with CAISO's transmission service model. Sacramento, however, asks the Commission to clarify that rollover rights apply to long-term firm service provided by RTOs and ISOs under Order No. 681 under what it terms the ''as good as or superior to'' standard.[766] Organization of MISO and PJM States assert that any changes for RTOs should be made through the stakeholder process. In its reply, Williams opposes permitting RTO stakeholders to determine changes in rollover rights policy in RTO regions, as it would result in disparate rules and practices and increased opportunities for discrimination, and therefore, the Commission should adopt a single policy applicable to all rollover rights.

1259. Other commenters raise different discrete issues. Morgan Stanley asks the Commission to amend *pro forma* OATT section 2.2 to include existing policy determinations with respect to the manner in which a transmission provider can curtail or, alternatively, must honor and accommodate rollover requests. Duke asks the Commission to abandon its existing policy prohibiting the restriction of rollover rights based on the potential exercise of other customers' rollover rights. Salt River asks the Commission to clarify that the proposal to extend the minimum term to five years does not change the definition in section 1.20 of the *pro forma* OATT that one year constitutes a long-term contract. AWEA, Constellation, and EPSA ask the Commission to allow transmission customers to waive their rollover rights.

Commission Determination

1260. As we explain in section IV.C above, RTOs and ISOs must submit a filing showing that their practices are consistent with or superior to the modifications made in the Final Rule. This does not necessarily mean that entities such as CAISO must create rollover rights if they do not have them already. Arguments regarding the applicability of rollover reform may be raised pursuant to the process described in section IV.C. We also clarify that our decision to extend the minimum term to five years does not change the definition in section 1.20 of the *pro forma* OATT that one year constitutes a long-term contract. Commenters have not offered sufficient justification for further clarifications to our rollover policies or amendments to section 2.2 at this time.

e. Effectiveness Upon Acceptance of Coordinated and Regional Planning Process and Transition

Comments

1261. Several transmission customers and other commenters support a linkage

[761] *See also* APPA Reply and TDU Systems Reply.

[762] *See* Order No. 888–A at 30,197.

[763] *Id.*

[764] While the Commission has not to date accepted any native load growth showing made by a transmission provider, it has recently set for hearing several such showings. *See, e.g., Southern Co. Servs., Inc.*, 116 FERC ¶ 61,050 (2006); *Nevada Power Co.,* 116 FERC ¶ 61,093 (2006).

[765] We note that this is consistent with the Commission's evaluation of rollover restrictions proposed by transmission providers in the past. *See, e.g., Nevada Power Co.*, 97 FERC ¶ 61,324 at 62,493 n.17 (2001).

[766] In its reply, CAISO argues that this request to expand the requirements of Order No. 681 is inappropriate both because the Commission and courts have already recognized that rollover rights under the *pro forma* OATT do not apply to entities like CAISO that do not offer traditional Order No. 888 network and point-to-point transmission services and because the Commission has already rejected such a requirement in Order No. 681 itself.

between rollover reform and planning, but do not support making rollover reforms effective upon acceptance of a transmission provider's coordinated and regional planning process, but rather on successful implementation of that process.[767] While both TAPS and TDU Systems support the link to planning generally, TAPS goes further and advocates holding transmission providers accountable for failing to plan and construct facilities needed to meet transmission customer needs. TDU Systems point out that the linkage to planning does not remedy concerns that the current market does not generally provide for five-year supply contracts.

1262. Some commenters, however, oppose linking the effectiveness of rollover reform to planning, arguing that rollover reform is needed as quickly as possible.[768] For example, Duke, Progress Energy, and Southern argue that FPA section 217 provides no indication that the native and network load protections inherent in rollover reform should be subject to conditions such as waiting for the Commission to accept a planning process. Moreover, Duke argues that developing a planning process will be time-consuming and that holding rollover reform hostage to it could motivate stakeholders with contracts shorter than five years to endlessly try to convince the Commission to delay acceptance of a transmission provider's planning process.

1263. Some commenters contend that linking planning and rollover reform will create differences in tariffs, with each transmission provider having a different effective date for rollover reforms.[769] MISO argues in its reply that the Commission should clarify in the Final Rule that its requirement that the new policy becomes effective upon acceptance of the transmission provider's coordinated and regional planning process is already met in regions where RTOs or ISOs provide service, as they already have Commission-approved regional transmission planning mechanisms in place. Bonneville argues in its reply for a consistent implementation date across all transmission providers so as to avoid another degree of complexity for customers requiring rollover capacity across multiple transmission providers' systems.

1264. As for the transition period proposed in the NOPR, a variety of commenters point out that, depending on the status of any given contract, making the one-year notice provision effective on acceptance of a transmission provider's planning process could leave some transmission customers unable to provide one-year notice if there is less than one year remaining on their contracts.[770] FirstEnergy, Exelon, Great Northern, and TAPS emphasize that existing transmission customers should be permitted one more rollover under the current rules, because the parties to such agreements have relied on the current rules in meeting their transmission needs. APPA and TAPS point out that transmission customers will need a sufficient amount of time to secure five-year power agreements to meet the new requirements. AWEA argues generally for a transition period during which existing customers can maintain or relinquish their existing rollover rights under current rules and become subject to new requirements only at the end of the transition period.

Commission Determination

1265. The Commission adopts the NOPR proposal to make rollover reform effective at the time of acceptance by the Commission of a transmission provider's coordinated and regional planning process also required by this Final Rule. We believe that rollover reform and transmission planning are closely related, because according to our longstanding policy, transmission service eligible for a rollover right must be set aside for rollover customers and included in transmission planning. We believe that it is necessary that reforms in both areas proceed together, and therefore, we reject the suggestion of some commenters that rollover reform proceed independent of transmission planning reform. We understand that our approach may result in differences in transmission providers' OATTs, with some having a different effective date for rollover reforms. However, because the effectiveness of rollover reform will be tied to acceptance of a transmission provider's coordinated and regional transmission planning process, rollover reforms in any given region generally should be effective within the same time period.

1266. We reject the arguments by some commenters that rollover reform be made effective upon the ''successful'' implementation, as opposed to acceptance by the Commission, of a transmission provider's coordinated and regional planning process. We believe that utilizing a subjective deadline, such as the successful implementation of the planning process, could result in significant confusion in the industry as to when rollover reforms should be effective. Furthermore, an existing filed and accepted transmission planning process, such as those that may be on file for RTOs and ISOs, does not trigger the effectiveness of rollover reform for transmission providers using the process. Such RTOs and ISOs and their transmission-owning members must, as discussed elsewhere in this Final Rule, comply with the planning reforms required by the Final Rule through the compliance filing procedures identified in section IV.C. It is Commission acceptance of these compliance filings that will trigger effectiveness of rollover reform for these transmission providers, assuming rollover reform is applicable to their tariff services in the first instance.

1267. In response to commenters' concerns that, depending on the effective date of rollover reform, certain customers may not have a year or more left on their contracts such that they can comply with the one-year notice provision, we emphasize that existing contracts with a rollover right at the time of effectiveness of rollover reform may exercise their next rollover based on the existing notice rules. It is only a rollover contract entered into or renewed after the effectiveness of rollover reform that must comply with the new rollover provisions, including the one-year notice requirement.

4. Modification of Receipt or Delivery Points

1268. Section 22 of the *pro forma* OATT provides that a transmission customer taking firm point-to-point service may modify its receipt and delivery points, *i.e.*, redirect its service, on either a non-firm or a firm basis. Section 22.1 (Modifications on a Non-Firm Basis) provides that, subject to certain conditions, a firm point-to-point customer may request transmission service on a non-firm basis over receipt and delivery points other than those specified in its service agreement (known as secondary receipt and delivery points) in amounts not to exceed its firm capacity reservation, without incurring an additional non-firm point-to-point service charge or executing a new service agreement. Section 22.2 (Modifications on a Firm Basis) provides that any request to modify receipt and delivery points on a firm basis shall be treated as a new request for service in accordance with

[767] *E.g.*, AWEA, Constellation, EPSA, Exelon, PGP, and PPM.

[768] *E.g.*, Bonneville, Duke, EEI Reply, North Carolina Commission Reply, Northwest IOUs, PNM–TNMP Reply, Progress Energy, Public Power Council, South Carolina E&G Reply, and Southern.

[769] *E.g.*, Northwest IOUs, Duke Reply and EEI Reply.

[770] *E.g.*, APPA, FirstEnergy, Northwest IOUs, PGP, and Public Power Council.

section 17 of the *pro forma* OATT (Procedures for Arranging Firm Point-to-Point Transmission Service), except that the transmission customer shall not be obligated to pay any additional deposit if the capacity reservation does not exceed the amount reserved in the existing service agreement. While such new request is pending, the transmission customer retains its priority for service at the existing firm receipt and delivery points specified in its service agreement.

1269. In Order No. 676, the Commission adopted the ''Standards for Business Practices and Communication Protocols for Public Utilities'' developed by the NAESB's Wholesale Electric Quadrant (WEQ).[771] Order No. 676 incorporated the aforementioned standards by reference into the Commission's regulations, required public utilities to implement the standards by July 1, 2006, and required public utilities to file revisions to their OATTs to include these standards.[772] The WEQ Standards include a number of standards addressing requirements for dealing with redirects on both a firm and non-firm basis.[773] All of the WEQ Standards dealing with redirects were adopted by the Commission in Order No. 676, except for WEQ Standard 001–9.7, which addresses the impact of a firm redirect on a long-term firm transmission customer's rollover rights under section 2.2 of the *pro forma* OATT. The Commission directed the WEQ to reconsider WEQ Standard 001–9.7 and to adopt a revised standard consistent with the Commission's policies.[774] The Commission also offered guidance to assist the WEQ in developing a standard that is consistent with Commission policy.[775]

NOPR Proposal

1270. In response to the NOI, commenters raised various concerns regarding redirects. Among other things, customers complained of difficulties obtaining redirected service, while transmission providers complained of a lack of clarity in the rules governing redirects. In the NOPR, the Commission stated its belief that a number of these concerns appeared to have been resolved by the adoption of the WEQ Standards in Order No. 676, which was issued after the NOI. The Commission sought comment on whether parties believed the WEQ Standards in fact addressed those concerns adequately.

1271. The Commission also stated its expectation that a number of other concerns raised in response to the NOI, while perhaps not yet addressed (or addressed fully) by a WEQ Standard, are nevertheless the types of issues that are appropriate for the WEQ process. The Commission therefore proposed that each commenter that continued to believe additional reform is necessary with regard to redirects evaluate whether its concerns would more appropriately be addressed by the WEQ as it considers its next version of its standards.[776] The Commission noted that WEQ was in the process of reevaluating WEQ Standard 001–9.7, dealing with redirects and rollovers, so that it is consistent with the Commission's guidance given in Order No. 676. The Commission requested comment on whether the WEQ process, along with the guidance provided by the Commission in Order No. 676, is sufficient to address the concerns of commenters that seek clarification on the interplay between redirects and rollovers.

1272. In the NOPR, the Commission acknowledged that there were additional, more fundamental concerns with regard to section 22 raised in response to the NOI. Customers generally argued that their ability to redirect to new points is stymied by a lack of ATC at the new points or the need for major upgrades, or that transmission providers take too long to process the redirect request. Transmission providers, on the other hand, complained of the administrative burdens and complexity (particularly with regard to reliability) of processing transmission customers' short-term changes in service and that there is often not enough time for the market to respond to capacity made available on a customer's original path. The Commission stated its belief that other proposed reforms in the areas of process, transmission planning, and ATC calculation should address transmission customer concerns regarding redirects. The Commission encouraged interested parties to submit a specific proposal, along with proposed revised *pro forma* OATT language, to the extent they believe the proposed reforms will not adequately address their concerns.

1273. The Commission also noted in the NOPR that several transmission providers had posted business practices that allow network customers either to substitute an off-system non-designated resource for a designated resource or to redirect the point of receipt associated with an existing network resource. The Commission proposed that network customers not be permitted to redirect network transmission service because network service involves no identified contract path and therefore should not be treated as a directable service.

a. Proposed Reliance on WEQ Process and Other OATT Reforms

Comments

1274. Commenters generally agree with the Commission that issues with respect to redirects of firm and non-firm transmission service are best addressed through the WEQ as established by NAESB, in accordance with Order No. 676 and the WEQ process for creating new standards.[777] Seattle argues that the NAESB standard setting process has worked well thus far and, as a result, other redirect issues should be first referred to NAESB as a standard-setting request. MISO states that it has serious concerns with the WEQ process and the Commission's unwarranted deference to NAESB to develop what will become binding business standards and practices.

1275. Nevada Companies recommend the following improvements for the NAESB process: use of a professional facilitator to keep discussions focused and moving; and mandatory surveys breaking down the sections on proposed NAESB standards after the first round of comments are received to determine if consensus exists on the proposed standards, since it appears that there are relatively few participants at NAESB meetings where standards are being drafted and relatively few commenters on those draft standards.

1276. Several commenters state that they agree with the Commission's proposal to rely on other proposed

[771] The WEQ was established by NAESB in response to a Commission order requesting the wholesale electric power industry to develop business practice standards and communication protocols by establishing a single consensus, industry-wide standards organization for the wholesale electric industry. *See* Order No. 676 at P 3–4.

[772] The standards will hereinafter be referred to as the WEQ Standards. The Commission adds a reference to the WEQ Standards in section 4 of the *pro forma* OATT, which identifies the Commission's regulations containing the terms and conditions relevant to the OASIS and standards of conduct.

[773] The requirements for dealing with redirects on a firm basis are found at WEQ Standard 001–9, *et seq.*, and the requirements for dealing with redirects on a non-firm basis are found at 001–10, *et seq.*

[774] Order No. 676 at P 52.

[775] *Id.* at P 53–61.

[776] The Commission noted in this regard that the WEQ's procedures ensure that all industry members can have input into the development of a business practice standard, whether or not they are members of NAESB, and each standard it adopts is supported by a consensus of the five industry segments: transmission, generation, marketers/brokers, distribution/load-serving entities, and end-users. *See* Order No. 676 at P 5 & n.5.

[777] *E.g.*, EEI, Imperial, NorthWestern, Southern, and Suez Energy NA.

reforms in the NOPR to resolve the remaining redirect issues.[778] Seattle generally agrees that the reforms proposed in the NOPR should improve the ability to assign and use transmission on a firm basis. EEI and NorthWestern state that the NOPR proposal to increase transparency in the calculation of ATC should assist transmission customers in both selecting transmission paths that may be available for redirect and understanding why certain paths cannot accommodate redirect transactions.

Commission Determination

1277. The Commission concludes that the proposed method for addressing remaining concerns with redirects—*i.e.*, relying on other reforms adopted in this Final Rule and in the Order No. 676 proceeding—is adequate to ensure that transmission providers do not engage in undue discrimination when a customer seeks to modify its receipt and delivery points on a firm basis. As explained throughout this Final Rule, the reforms adopted herein address the remaining opportunities for undue discrimination. Planning and ATC reforms will give transmission customers more accurate and complete ATC information when evaluating their redirect options. Increased transparency will give transmission customers the information they need to evaluate a transmission provider's denial of a request to redirect. Modifications to the process for requesting and securing firm point-to-point service will improve the ability to redirect transmission service to new points pursuant to section 22 and ensure complete and timely responses from transmission providers. The Commission therefore concludes that no further reforms specific to redirects are necessary at this time.

1278. The Commission also concludes that the NAESB WEQ is the appropriate standard-setting body for developing business practices and implementing the Commission's redirect policy. The Commission will refrain from commenting here on the NAESB process itself because we believe that the industry is best situated to determine how to structure the standard-setting process to provide for the widest possible participation and consensus. We nevertheless clarify that, consistent with precedent, NAESB is charged with implementing Commission policy through business practices.[779] The Commission finds that the NAESB WEQ is an acceptable standards development process, representing a cooperative effort by industry participants to develop business practices that enhance the efficiency of the electric grid.[780] Where necessary, NAESB participants may seek clarification of Commission policy so that NAESB may develop the appropriate standards.

b. Redirects and Rollovers Rights

Comments

1279. Regarding the interaction between redirects and rollovers, some commenters request that the Commission clarify what they view as an inconsistency between Order No. 676, the Commission's existing *pro forma* OATT, and the rollover proposal in the NOPR. Specifically, Bonneville, MISO, and Southern argue that, contrary to the *pro forma* OATT and NOPR, Order No. 676 improperly suggested in an example that a short-term redirect of a long-term service agreement gives the customer rollover rights for the new path. TranServ supports placing the following two conditions on the receipt of rollover rights for redirects: a redirect on a firm basis must be for one year or longer, and the redirect must be for the entire remaining term of the parent (original) request.[781] If these conditions are met, TranServ contends that the customer will be granted rollover rights on the redirect path and lose the rollover rights held on the original path. If the customer wishes to retain rollover rights on the original path, TranServ continues, it will have the option to submit multiple redirect requests of less than one year in duration for the term desired. With respect to WEQ Standard 001.9.7, MISO incorporates by reference its opposition to the Commission's adoption of the proposed transfer of rollover rights on the redirected path in its request for rehearing of Order No. 676. There MISO argued that there should be no rollover rights on a redirect path and that the guidance in Order No. 676 requiring the transmission provider "to offer rollover rights to a customer requesting a firm redirect if rollover rights are available on the redirect path" was inconsistent with the *pro forma* OATT.

Commission Determination

1280. Commission policy allows a redirect of firm, long-term service to retain rollover rights, even if the redirect is requested for a shorter period. In other words, the rollover right follows the redirect, regardless of the duration of the redirect. Contrary to the comments of Bonneville, MISO, and Southern, the Commission did not impose this requirement for the first time in Order No. 676, but merely provided guidance to the industry by restating Commission policy on this matter. The Commission has explained in prior orders that a transmission customer making a firm redirect request does not convert its original long-term firm transmission service to short-term service, nor does it lose its rollover rights under its long-term firm transmission service agreement. The Commission's concern underlying this policy is that long-term customers should not need to choose between redirecting on a firm basis and maintaining rollover rights, rather their rollover rights should be retained consistent with the long-term nature of their service.

1281. In *Commonwealth Edison Co.*, the Commission explained that a "request to change a delivery point on a firm basis for one month and then to revert to its original delivery point does not convert its existing long-term firm transmission service agreement into two separate short-term transmission service agreements." [782] The Commission stated that section 22.2 was intended to provide flexibility to transmission customers to permit them to react in a competitive market and that some amount of this flexibility would be lost if a long-term firm transmission customer seeking to modify its delivery points would lose its rollover rights.[783]

1282. The Commission affirmed this policy in *American Electric Power Service Corp.*[784] In that case, a long-term transmission customer (Exelon) had been granted a short-term redirect, but denied rollover rights on the redirected path. The Commission found the denial of rollover rights was improper, since the "redirect request made by Exelon did not convert Exelon's long-term firm transmission service to short-term service, and, therefore, did not affect Exelon's rollover rights under its long-term firm transmission service agreement." [785] Thus, there is no inconsistency between the Commission's redirect policy and Order No. 676.

[778] *E.g.*, EEI, NorthWestern, and Seattle.

[779] *See Standards for Business Practices of Interstate Natural Gas Pipelines,* Order No. 587–N, FERC Stats. & Regs. ¶ 31,125 at P 23 (2002).

[780] *See* Order No. 676 at P 12.

[781] TranServ explains that these are two primary features in a revised WEQ 001–9.7 standard that was open for public comment.

[782] 95 FERC ¶ 61,027 at 61,083 (2001).

[783] The Commission, however, recognized that this flexibility was not unlimited—any change to a delivery point is treated as a new request for service for purposes of the availability of capacity.

[784] 97 FERC ¶ 61,207 at 61,905–06 (2001).

[785] *Id.*

c. Redirects as New Requests for Service

Comments

1283. With respect to the provision in section 22.2 of the *pro forma* OATT specifying that requests to redirect on a firm basis be considered new requests for service, LPPC and NPPD ask that this provision be modified to ensure that a customer redirecting its service will retain a higher priority for service in the transmission provider's queue than new customers. LPPC argues that it is inequitable to require customers to compete for capacity as though their loads were incremental to the system when they are simply changing their receipt points as a matter of necessity (since suppliers may commence serving other loads or cease doing business). EEI argues on reply that, if LPPC's proposal would give customers priority at new points of receipt and delivery regardless of whether the redirected service creates system impacts different from the old service, the proposal would replace ''first-come, first-served'' priority with a system in which customers would never know for sure whether their own requests for service would be displaced by subsequent requests for redirected service. EEI cautions that the transmission system simply cannot be planned and constructed with enough spare capacity to allow any customer to redirect service to any point that it chooses at any time.

1284. Bonneville similarly argues that a redirect request should meet the same term and notice requirements as a new request given that the transmission provider's planning horizon and the amount of time needed to remarket unused capacity is no different for a redirect and a new transmission service request. APPA argues on reply that it is unclear how Bonneville's request would affect load-serving transmission customers that cannot obtain power supply agreements of a term sufficient to dovetail with the term requirements for a new request. Imperial recommends that redirects be evaluated using ATC at the time of the redirect request, like any other new request for service, but that the transmission provider be given additional time to determine whether native load growth will prevent rollover rights for the redirects.

Commission Determination

1285. Section 22.2 of the *pro forma* OATT provides that redirects ''shall be treated as a new request for service in accordance with section 17,'' except that the transmission customer may not be required to pay an additional deposit in certain circumstances. Therefore, a redirect right does not grant the customer access to system capacity or queue position different from other customers submitting new requests for service. A redirect request must be evaluated in accordance with section 17 using the same system assumptions and analysis applicable to any other new request for service, including whether sufficient ATC exists to accommodate the request. The Commission concludes it would be inappropriate, and contrary to the *pro forma* OATT, to grant redirects special queue treatment.

1286. Regarding Imperial's request that transmission providers be given additional time to determine whether native load growth will prevent rollover rights for the redirects, we find that redirects should be studied like any other new request for firm point-to-point service. Transmission providers must examine whether any request, a firm redirect request or a new service request, would be affected by future native load growth resulting in possible rollover rights restrictions, so we see no need to provide additional time for transmission provider analysis of firm redirect request.

d. Pricing for Redirects

Comments

1287. TranServ requests that the Commission resolve a disagreement among WEQ participants regarding the pricing of redirects as requests for new service. TranServ asks whether the failure to charge an incremental uplift between the original and redirected rate (*e.g.*, respectively, the monthly rate and daily on-peak rate) would constitute the offering of a discount for daily service that in turn must be posted for all other paths to the same point of delivery. TranServ argues that it is reasonable to charge an incremental uplift such that the rate paid by the redirect customer would be on par with that paid by any other transmission customer reserving (daily) short-term firm service of like duration (*i.e.*, a ''new request for service''), and the customer would pay the difference between the daily on-peak rate and 1/30th of the monthly rate.

1288. Southern argues that, with respect to the price for redirects, if redirected hourly firm service is more valuable than firm service, economic theory would dictate that customers should be required to pay for that added value.

Commission Determination

1289. The Commission has not established a single, industry-wide pricing policy for redirects and did not propose a pricing policy in the NOPR. As a result, a uniform pricing method for redirects is beyond the scope of this proceeding. Nevertheless, we note that the Commission explained in a recent order that its policy does not allow transmission providers to collect additional charges when a firm point-to-point customer redirects on a non-firm basis.[786] The Commission concluded that it would not subject non-firm redirects to the *Appalachian* Method of pricing,[787] which is premised on the assumption that a customer using the transmission system for the 16 peak hours of the day should pay the same contribution to fixed costs as a customer who has reserved capacity on a daily basis. This is because the redirecting customer already would have paid for firm service over all on-peak and off-peak hours during the reservation period of its service, therefore, there is no need to ensure that the customer pays a premium for the opportunity to cherry pick the best hours each day. Furthermore, because the Commission is not requiring the provision of hourly firm service, Southern's argument regarding redirected hourly firm service is now moot.

e. Other Issues

Comments

1290. EEI agrees with the Commission's proposal to clarify that network customers may not redirect network transmission service. Alberta Intervenors contend that undue discrimination remains because the flexibility to modify points of receipt and delivery that the network customer enjoys through ''parking'' and ''hubbing'' is not likewise granted to a point-to-point customer. Alberta Intervenors recommends that the *pro forma* OATT either make a common service available to all participants (not just network customers) or prohibit network customers from using point-to-point services for parking and hubbing.

1291. Imperial asks the Commission to clarify that a transmission customer should not be able to make multiple redirects. Imperial explains that this clarification would address two concerns: multiple short-term changes raise reliability concerns and often there is insufficient time for the released capacity to be used by another customer; and the burden on properly scheduling for reliability increases exponentially when there are redirects of redirects.

[786] *Midwest Independent Transmission System Operator, Inc.*, 118 FERC ¶ 61,095 at P 79–85(2007).

[787] *See Appalachian Power Co.*, 39 FERC ¶ 61,296 (1987).

1292. MISO/PJM States argue that because RTOs are not likely to engage in discrimination with respect to redirects, the Commission should not modify RTO redirect policies in the instant rulemaking proceeding.

Commission Determination

1293. The Commission adopts the NOPR proposal and finds that network customers may not redirect network service in a manner comparable to the way customers redirect point-to-point service. Unlike point-to-point service, network service involves no identified contract path and thus is not a directable service. A network customer seeking to substitute one resource for another already has the ability under the *pro forma* OATT to terminate its existing designation and designate a new resource on an as-available basis. If necessary, the network customer may then request to redesignate its original network resource by making a request to designate a new network resource. Alternatively, the network customer could use secondary network service if it wants to substitute a non-designated network resource for a designated network resource on an as-available basis.

1294. For similar reasons, the Commission denies Alberta Intervenors' request. The Commission has explained that customers must choose between point-to-point and network services, each of which has its own advantages and risks.[788] The Commission declined to implement a single form of transmission service in Order No. 888, concluding that point-to-point and network services are the appropriate base-line services under the *pro forma* OATT, and Alberta Intervenors offer no justification for departing from that approach now. Alberta Intervenors parking and hubbing related arguments alleging that network service is commonly used to purchase power intended for sales to third parties is addressed in section V.D.7 of this Final Rule. Although we deny Alberta Intervenors' request, we expect that the reforms adopted in this Final Rule will provide point-to-point customers with increased service options and flexibility.

1295. Implementing Imperial's proposal would prevent customers from redirecting for a short period or periods of time and then redirecting back to their original points, making redirects a less valuable option for customers. Multiple redirects are allowed only if the customer can meet the scheduling and other requirements for new requests for service under the *pro forma* OATT. As long as the customer meets these requirements, the Commission believes that the ability to redirect service does not present an unreasonable burden to transmission providers. As for applicability to RTOs and ISOs, we explain our compliance requirements in section IV.C of this Final Rule. To the extent an RTO's or ISO's redirect policy does not conform to the *pro forma* OATT, as amended by this Final Rule, the RTO or ISO must demonstrate that its policy is consistent with or superior to the *pro forma* provisions in accordance with the compliance procedures set forth in that section.

5. Acquisition of Transmission Service

a. Processing of Service Requests

1296. The *pro forma* OATT includes requirements that transmission providers process requests for transmission service in a timely fashion. Section 17.5 (Response to a Completed Application) and section 18.4 (Determination of Available Transmission Capability) of the *pro forma* OATT provide that following the receipt of a completed application for service, the transmission provider must respond to transmission customer requests for determinations of the availability of firm and non-firm transmission capacity on a timely basis. The transmission provider must make the determination as soon as reasonably practicable after receipt but no later than certain specified time periods (or such time periods generally accepted in the region).

1297. Section 19 (Additional Study Procedures for Firm Point-to-Point Transmission Service Requests) of the *pro forma* OATT provides deadlines that transmission providers must adhere to in issuing system impact study agreements and facilities studies agreements and that transmission customers must abide by in responding to these study agreements. Section 19 requires transmission providers to use due diligence to complete system impact studies and facilities studies within 60 days. Section 32 of the *pro forma* OATT (Additional Study Procedures for Network Integration Transmission Service Requests) contains similar due diligence deadlines for completing system impact studies and facilities studies associated with requests for network service.

(1) Posting Performance Metrics

NOPR Proposal

1298. In the NOPR, the Commission proposed to require transmission providers to post on their OASIS sites metrics that track their performance in processing system impact studies and facilities studies associated with requests for transmission service. The Commission proposed that transmission providers calculate the proposed performance metrics separately for affiliates and non-affiliates and for requests for short-term and long-term transmission service.

1299. In addition, the Commission proposed to require a notification filing and the posting of additional metrics if a transmission provider completes more than 20 percent of non-affiliates' studies outside of the 60-day due diligence deadline in the *pro forma* OATT for two consecutive quarters. Starting the quarter after a notification filing, the transmission provider would be required to post the following information on OASIS: (1) The average, across completed system impact studies, of the employee-hours expended per completed system impact study, (2) the average, across completed facilities studies, of employee-hours expended per completed facilities study, (3) the number of employees devoted to processing system impact studies, and (4) the number of employees devoted to processing facilities studies. The Commission proposed that transmission providers post these additional performance metrics until they process at least 90 percent of all system impact and facilities studies within 60 days after the study agreement has been executed. The additional performance metrics also would be calculated separately for affiliates' and non-affiliates' requests for transmission service and for short-term and long-term transmission service.

Comments

Standard Performance Metrics

1300. Transmission customers and a number of other commenters generally support or do not oppose the Commission's proposal to require transmission providers to post performance metrics.[789]

1301. Southern and Salt River oppose the proposal, arguing that most of the data needed to compute the metrics is already available on OASIS. Southern asserts that the NOPR does not explain why the currently available information is inadequate or how the proposed metrics would not be duplicative and, thus, does not fully justify the need for reform. Southern also argues that the Commission's proposal will impose

[788] Order No. 888–A at 30,260.

[789] *E.g.*, ELCON, Suez Energy NA, Powerex, Seattle, TAPS, Constellation, Entegra, NRECA, TDU Systems, Regional Electricity Committee, MISO, MidAmerican, FirstEnergy, Tacoma, EEI, Nevada Companies, and TranServ.

costs and burdens on transmission providers, and ultimately those who use their services, that do not correspond with the limited benefits that might be gained. Salt River believes that performance tracking requirements should be established on a case-by-case basis in response to complaints. NorthWestern believes the 60 days should be a target, but not a deadline, and, as such, transmission providers should not be required to report performance metrics that summarize the time they take to perform the studies.

1302. Several commenters requested clarification on certain features of the Commission's proposal. Nevada Companies asks the Commission to be very specific as to what statistical data items are to be reported on the OASIS so that transmission providers do not inadvertently violate the confidentiality of their transmission customers. PNM-TNMP requests clarification that the standards set out in the NOPR are solely applicable to processing of transmission delivery service requests, and not to interconnection service requests. Insofar as the Commission determines that performance metrics should be posted, Southern asks the Commission to clarify that the proposed posting of performance metrics also would be required of RTOs and ISOs.

1303. A number of commenters suggest that the Commission modify the performance metrics that transmission providers are required to post. EEI suggests that NAESB develop the metrics that transmission providers are required to post, using the metrics contained in the NOPR as guidance. EEI and MidAmerican suggest that the performance metrics include information about the degree to which transmission customers delay the study process. MISO suggests that transmission providers post metrics related to the time transmission customers take to respond to the results of completed system impact studies and facilities studies. Southern asserts that fewer metrics should be required and that they should relate directly to the study-timing concerns raised in the NOPR. Bonneville and MISO argue that transmission providers should not have to post information about the cost of transmission system upgrades recommended in the request studies. Bonneville believes that the average cost of recommended upgrades is misleading because it will mask the wide variation in such costs. MISO suggests that transmission providers also report the standard deviation for study completion times. Southern asserts further that the OATT does not specifically provide for a system impact study or facilities study to be performed on a short-term basis, so any metrics required as part of OATT reform should not include short-term requests. CREPC suggests that performance metrics be calculated separately for renewable resources.

1304. Several commenters suggest that transmission providers post additional information to further enhance transparency. A number of commenters suggest that the Commission require the posting of the disposition of all transmission service requests, including those not requiring studies.[790] TDU Systems suggest that the Commission require transmission providers to post the parameters of each denied request. MISO suggests that transmission providers provide a narrative to explain any anomalous study costs that may affect the posted average cost. If a transmission provider anticipates that it will miss the study deadline date, NRECA suggests that it should post that information, the expected finish date, and a reason for not being able to meet the deadline.

1305. EEI recommends that the Commission delegate to NAESB the responsibility for developing the Standard and Communications Protocols, business practices and OASIS modifications that will be necessary to provide the metrics.

Additional Performance Metrics (After Two Quarters of Late Studies)

1306. EEI and Southern oppose the Commission's proposal to require transmission providers that fail to complete studies in a timely manner to post additional performance metrics that measure the labor input used to complete studies. EEI asserts that there is little value to be gained from posting the additional information that the Commission proposes. EEI believes the information concerning the number of employees who perform studies will not be determinative of responsibility for the delay because the significant issue is whether the number of studies that the transmission provider is required to perform or the total amount of time needed to perform studies has increased significantly or whether customers caused the delays. Southern questions the Commission's legal authority to require transmission providers that do not complete studies in a timely manner to post additional performance metrics, citing *Cal. Ind. Sys. Operator Corp.* v. *FERC*.[791] Southern characterizes the Commission's proposal as a punishment for delays in processing request studies.

1307. Several other commenters suggest changes to the Commission's proposal. Southern believes the submission of a notification of extenuating circumstances should suspend the obligation to post the additional metrics proposed in the NOPR. EEI and Southern argue that the Commission should be certain that it is collecting such information only from those transmission providers that, for no other reason except themselves, fail to consistently evaluate studies within the 60-day due diligence period. Therefore, if a transmission provider demonstrates that delays in completing studies are due to extenuating circumstances, then EEI and Southern believe the Commission should not require the transmission provider to post the additional metrics. MISO believes the Commission should exempt RTOs from the additional employee performance metrics proposed in the NOPR for the same reason that the Commission proposed to exempt RTOs from operational penalties for untimely completion of studies, as MISO claims the additional posting requirements are in the nature of penalty. Bonneville believes the proposed metrics will be misleading whenever a transmission provider employs outside consultants to perform or assist with studies. Therefore, Bonneville suggests that the Commission add two other metrics, the number of studies performed entirely by consultants and, in the case of studies performed by a combination of employees and consultants, the average percentage of the study performed by consultants.

Commission Determination

Standard Performance Metrics

1308. The Commission will require transmission providers to post the performance metrics proposed in the NOPR, as modified by this Final Rule. The proposed metrics will enhance the transparency of the study process and shed light on whether transmission providers are processing request studies in a non-discriminatory manner. We also agree with comments by MidAmerican and EEI that transmission providers should be able to track delays in the study process caused by transmission customers. Doing so will allow the Commission and market participants to determine the extent to which delays by transmission customers are causing transmission providers to process request studies on an untimely basis, which will add needed transparency to the study process.

[790] *E.g.*, CREPC, MISO, Constellation, and TDU Systems.

[791] 372 F.3d 395, 404 (D.C. Cir. 2004).

Therefore, we will revise the performance metrics transmission providers are required to post to include metrics that track delays by transmission customers.

1309. Transmission providers will be required to post the performance metrics, outlined below, for each calendar quarter. Transmission providers will be required to begin tracking their performance upon the effective date of this Final Rule and keep the quarterly performance metrics posted on their OASIS sites for three calendar years. The transmission provider will be required to post the quarterly performance metrics within 15 days of the end of the quarter. The performance metrics outlined below must be calculated separately for affiliates' and non-affiliates' requests, in order to identify potential instances when the transmission provider is processing requests on a discriminatory basis. The transmission provider is required to aggregate studies associated with requests for short-term and long-term transmission service when calculating the metrics defined below. While a transmission provider could offer to study a request for short-term firm point-to-point transmission service, we acknowledge that the transmission customer often is unwilling to pay for such a study. Therefore, to ease the reporting burden, the transmission provider is not required to report the performance metrics defined below separately for requests for short-term and long-term firm point-to-point transmission service. A transmission provider is also required to post performance metrics for studies that it conducts for RTOs.

1310. A transmission provider is required to post the following set of performance metrics on a quarterly basis:

- Process time from initial service request to offer of system impact study agreement pursuant to sections 17.5, 19.1 and 32.1 of the *pro forma* OATT
  - ○ Number of new system impact study agreements delivered to transmission customers
  - ○ Number of new system impact study agreements delivered to the transmission customer more than 30 days after the transmission customer submitted its request
  - ○ Average time (days) from request submittal to change in request status
  - ○ Average time (days) from request submittal to delivery of system impact study agreement
  - ○ Number of new system impact study agreements executed
- System impact study processing time pursuant to sections 19.3 and 32.3 of the *pro forma* OATT
  - ○ Number of system impact studies completed
  - ○ Number of system impact studies completed more than 60 days after receipt of executed system impact study agreement
  - ○ Average time (days) from receipt of executed system impact study agreement to date when completed system impact study made available to the transmission customer
  - ○ Average cost of system impact studies completed during the period
- Service requests withdrawn from system impact study queue
  - ○ Number of requests withdrawn from the system impact study queue
  - ○ Number of system impact studies withdrawn more than 60 days after receipt of executed system impact study agreement
  - ○ Average time (days) from receipt of executed system impact study agreement to date when request was withdrawn from the system impact study queue
- For all system impact studies completed more than 60 days after receipt of executed system impact study agreement, average number of days study was delayed due to transmission customer's actions (*e.g.*, delays in providing needed data)
- Process time from completed system impact study to offer of facilities study pursuant to sections 19.4 and 32.4 of the *pro forma* OATT
  - ○ Number of new facilities study agreements delivered to transmission customers
  - ○ Number of new facilities study agreements delivered to transmission customers more than 30 days after the completion of the system impact study
  - ○ Average time (days) from completion of system impact study to delivery of facilities study agreement
  - ○ Number of new facilities study agreements executed
- Facilities study processing time pursuant to sections 19.4 and 32.4
  - ○ Number of facilities studies completed
  - ○ Number of facilities studies completed more than 60 days after receipt of executed facilities study agreement
  - ○ Average time (days) from receipt of executed facilities study agreement to date when completed facilities study made available to the transmission customer
  - ○ Average cost of facilities studies completed during the period
  - ○ Average cost of recommended upgrades for facilities studies completed during the period
- Service requests withdrawn from facilities study queue
  - ○ Number of requests withdrawn from the facilities study queue
  - ○ Number of facilities studies withdrawn more than 60 days after receipt of executed facilities study agreement
  - ○ Average time (days) from receipt of executed facilities study agreement to date when request was withdrawn from the facilities study queue
- For all facilities studies completed more than 60 days after receipt of executed facilities study agreement, average number of days study was delayed due to transmission customer's actions (*e.g.*, delays in providing needed data).

1311. In response to Nevada Companies request that we clarify the statistical data items that are to be reported on OASIS pursuant to the Commission's proposal, we reiterate that transmission providers are required to provide summary data as defined above. We do not believe these data will violate the confidentiality of any transmission customer, even in the event the transmission provider has worked on a limited number of studies. We clarify that the performance metrics posting requirement discussed above is solely applicable to processing of transmission delivery service requests, and not to interconnection service requests. Finally, we clarify that RTOs and ISOs also are required to post the performance metrics described above. As we discuss below, we believe all transmission providers should be subject to the same reporting requirements.

1312. We disagree with Southern and Salt River which argue that the data already on OASIS is sufficient to accomplish our goal to enhance transparency of the transmission provider's request study processing. First, the data available on the OASIS template *transstatusaudit* does not contain the information necessary to calculate all of the performance metrics proposed in the NOPR.[792] For instance,

[792] The OASIS template *transstatusaudit* is defined in the Standards and Communications Protocols section of NAESB's WEQ Business Practice Standards. The template *transstatusaudit* is the audit component to OASIS template *transstatus* and, as such, contains information regarding the

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transstatusaudit allows one to determine when a request was moved from ''received'' to ''study'' and then to ''accepted'' or ''counteroffer''. Depending on when the transmission provider moves the request into ''study,'' this information does not allow one to determine either whether the transmission provider provided a system impact study agreement within 30 days or whether the transmission provider completed the system impact study within 60 days. In addition, the transmission provider is required to make the data in *transstatusaudit* available on OASIS for only 90 days and available by request for three years.[793] As a result, market participants would be required to calculate the performance metrics they desire on a quarterly basis if they want to use just the data posted on OASIS. Finally, downloading *transstatusaudit* data for specific OASIS requests that required a system impact study or feasibility study can be cumbersome due to the manual nature of the download process. The transmission provider has the data necessary to calculate the proposed performance metrics readily available. We believe it is more efficient for a single transmission provider to calculate the performance metrics for its system rather than have multiple interested parties calculate the performance statistics for each transmission provider of interest.

1313. We also disagree with Southern's assertion that the costs and burdens to transmission providers are not justified by the benefits that might be gained. We are concerned that, under the existing *pro forma* OATT, transmission providers do not have adequate incentives to conduct studies on a timely and nondiscriminatory basis. First, transmission providers have incentives to discriminate against third parties and in favor of their affiliates (*i.e.*, to delay the study requests of nonaffiliates, but act more quickly on those of its affiliates). Second, transmission providers also can lack incentives to provide sufficient staff resources to support increasing demands in the study process. Given that most of the costs associated with the study process are operational, transmission providers, at most, will recover those costs without profit (*i.e.*, a return) and, if the demands of the study process are increasing, fail to recover such cost increases if the transmission provider is between rate cases. We therefore believe that there are several reasons that greater transparency is required to provide the correct incentives to comply with the *pro forma* OATT provisions respecting studies.

1314. We also note that virtually all commenters agree with our proposal to require transmission providers to calculate the above performance metrics. This support stems, in part, from transmission customers' perception that transmission providers do not exert sufficient effort to complete requests in a timely manner.[794] Delays in processing study requests can cause customers to incur material financial damage. Moreover, the data needed to calculate the required performance statistics is readily available to the transmission provider and, therefore, the cost to the transmission provider will be small relative to the benefits of enhanced transparency and assurance that the transmission provider is processing request studies in a timely and non-discriminatory fashion.

1315. Based on our experience and the comments received in response to the NOI and NOPR, the Commission believes the steps we take here are necessary to increase transparency for the processing of service requests by all transmission providers. It would be inappropriate, as some commenters suggest, to wait for specific complaints about specific transmission providers before requiring the transmission provider to calculate the performance metrics defined above. We conclude that the reporting requirements adopted in this Final Rule must be applied to all transmission providers in order to enhance the transparency of the study process and ensure that transmission provider processes study requests in a timely and non-discriminatory fashion for all transmission customers. The fact that the 60-day timeframe in the *pro forma* OATT is a target and not a deadline does not change the fact that requiring all transmission providers to post the performance metrics defined above will enhance the transparency of the study process.

1316. We will not adopt any of the changes to the proposed performance metrics requested by commenters, other than adding metrics to track delays by customers as discussed above. The Commission is in a better position to determine the specific performance metrics that will achieve our policy goals and thus we will not request that NAESB develop the metrics to be posted.[795] We believe the set of performance metrics we have chosen strike the appropriate balance between requiring information that will enhance transparency and help ensure that the transmission provider is processing request studies in a timely and non-discriminatory fashion while limiting the burden the transmission provider faces. For instance, we believe the performance metrics that address the cost of system impact studies and facilities studies as well as the cost of any proposed transmission upgrades can be calculated with relatively little effort by the transmission provider and should provide meaningful benefits to transmission customers. The transmission provider readily knows the cost of studies it completes and the costs of proposed system upgrades and summaries of this information should enhance the transmission customer's ability to decide whether to submit a request for service that may result in a study offer.

1317. We do not believe the relative benefits and burdens justify requiring the transmission provider to post performance metrics beyond those adopted in this Final Rule. For instance, requiring the transmission provider to calculate additional summary information or post long narratives to explain anomalous upgrade costs do not appear necessary at this time to achieve our stated policy goals, particularly since transmission customers can request data associated with completed system impact studies and facilities studies pursuant to section 37.6(b)(2)(iii) of the Commission's regulations.[796] In addition, we do not believe transmission customers, beyond the transmission customer directly affected, would benefit from the information NRECA suggests the transmission provider should be required to post when it anticipates that it will not complete a study within the 60-day due diligence timeframe. Section 19.3 of the *pro forma* tariff already requires the transmission provider to notify the affected transmission customer when it will not be able to complete a study within the 60-day due diligence timeframe, provide an expected completion date, and explain why additional time is needed. We do

type of transmission service requested, affiliate status, date and time the transmission service was requested, and the date and time of all changes in request status (*e.g.*, place in study mode, confirmed or withdrawn).

[793] 18 CFR 37.7(b).

[794] *E.g.*, Constellation, EPSA NOI Comments, Arkansas Cities NOI Comments, APPA NOI Reply Comments, and Powerex NOI Reply Comments 795 As noted in P 1318, we direct public utilities working through NAESB to develop protocols for posting the performance metrics required here so they will be posted in a consistent fashion.

[795] As noted in P 1318, we direct public utilities working through NAESB to develop protocols for posting the performance metrics required here so they will be posted in a consistent fashion.

[796] 18 CFR 37.6(b)(2)(iii).

not believe other transmission customers would benefit enough from this information to justify requiring the transmission provider to post it. Similarly, we do not believe the benefit to market participants justifies the burden of requiring transmission providers to calculate performance metrics separately for renewable resources.

1318. We agree, however, with EEI's recommendation that the Commission delegate to NAESB the responsibility for developing the Standard and Communications Protocols, business practices and OASIS modifications that will be necessary to provide the performance metrics adopted above. NAESB is in the best position to develop the standards and the processes by which the performance metrics are posted.

Additional Performance Metrics (after two quarters of late studies)

1319. The Commission also adopts the NOPR proposal to require transmission providers to submit a notification filing with the Commission in the event the transmission provider processes more than 20 percent of non-affiliates' studies outside of the 60-day due diligence deadlines in the *pro forma* OATT for two consecutive quarters. This filing must be filed within 30 days of the end of the second quarter during which the transmission provider processes more than 20 percent of non-affiliates' studies outside of the 60-day due diligence deadlines in the *pro forma* OATT. For the purposes of calculating this notification trigger, the transmission provider is required to aggregate all system impact studies and facilities studies that it completes during the quarter for non-affiliates.[797] The transmission provider may explain in its notification filing that it believes there are extenuating circumstances that prevented it from meeting the deadlines in the *pro forma* OATT.

1320. As the Commission proposed in the NOPR, starting the quarter following a notification filing, the transmission provider will be required to post: (1) The average, across completed system impact studies, of the employee-hours expended per completed system impact study; (2) the average, across completed facilities studies, of employee-hours expended per completed facilities study; (3) the number of employees devoted to processing system impact studies; and (4) the number of employees devoted to processing facilities studies. The transmission provider is not required to post these additional performance metrics separately for affiliates' and non-affiliates' requests for transmission service and for short-term and long-term transmission service. The transmission provider is instead required to aggregate studies associated with requests for short-term and long-term transmission service when calculating these additional metrics. The transmission provider is not required to post the additional metrics if the Commission concludes that delays in completing studies are due to extenuating circumstances. However, the transmission provider is required to post the additional metrics while the Commission considers the transmission provider's notification filing arguing that extenuating circumstances prevented it from processing request studies on a timely basis. Based on the timing described in this Final Rule, the transmission provider will be required to post the additional performance metrics approximately two months after the provider makes its notification filing. The Commission will have this time to evaluate the transmission provider's contention that it was unable to complete request studies due to extenuating circumstances. As a result, we expect the transmission provider with legitimate extenuating circumstances typically will not have to post any additional metrics.

1321. We disagree with those arguing that information concerning the number of employees who perform studies will not be determinative of responsibility for the delay. The transmission provider will have the right to establish that it is unable to perform studies in a timely manner because of factors outside its control. We received a number of comments to the NOPR and NOI that suggest that transmission customers believe transmission providers fail to complete studies on a timely basis because they do not have sufficient staff to perform the studies.[798] As explained above, this is one of the concerns that has led us to adopt these reforms. The additional metrics will serve to shed light on the transmission provider's resource commitment, enhance the transparency of the study process, and increase the transmission provider's incentive to staff its study function appropriately.

1322. The additional posting requirement is not a penalty or a punishment. We opted not to require the transmission provider to post these additional performance metrics on a regular basis out of a desire to limit the transmission provider's reporting burden. However, once the transmission provider has stopped completing studies on a timely basis, we believe the enhanced transparency justifies the additional reporting burden. As a result, ISOs and RTOs also will be required to post the additional performance metrics described above. We disagree with Southern's argument that we lack jurisdiction to require additional posting. The posting requirements are directly related to *pro forma* OATT obligations that are necessary to remedy undue discrimination and, hence, necessarily derive from our broad discretion in fashioning remedies to undue discrimination. We are not attempting to dictate a transmission provider's internal staffing decisions; rather, we illuminate the transmission provider's compliance with its *pro forma* OATT obligations to perform studies within certain deadlines and on a nondiscriminatory basis.

1323. We will not add the two other metrics suggested by Bonneville regarding the number of studies performed entirely by consultants and, in the case of studies performed by a combination of employees and consultants, the average percentage of the study performed by consultants. Rather, transmission providers should include the time spent by consultants on studies in the performance metrics defined above.

(2) Operational Penalties for Late Studies

NOPR Proposal

1324. The Commission proposed to impose operational penalties when transmission providers routinely fail to meet the 60-day due diligence deadlines prescribed in sections 19.3, 19.4, 32.3 and 32.4 of the *pro forma* OATT. Under the proposal, a transmission provider who processes more than 20 percent of non-affiliates' studies outside of the 60-day due diligence deadlines in the *pro forma* OATT for two consecutive quarters would be required to notify the Commission. In this notification filing, the transmission provider may explain that it believes there are extenuating circumstances that prevented it from meeting the deadlines in the *pro forma* OATT. The transmission provider

[797] For instance, if the transmission provider completes 4 non-affiliates' system impact studies during the quarter with 2 completed more than 60 days after the system impact study agreement was executed and completes 2 non-affiliates' facilities studies during the quarter with none completed more than 60 days after the facilities study agreement was executed, then the transmission provider will be deemed to have completed 2 out of 6 (33 percent) studies outside of the deadlines in the *pro forma* OATT.

[798] *E.g.*, Constellation, EPSA NOI Comments, Arkansas Cities NOI Comments, APPA NOI Reply Comments, and Powerex NOI Reply Comments.

would be subject to an operational penalty if it continues to be out of compliance [799] with the deadlines prescribed in the *pro forma* OATT for each of the two quarters following its notification filing.

1325. The Commission proposed that the operational penalty be assessed on a quarterly basis, starting with the quarter following the notification filing and continuing until the transmission provider completes at least 90 percent of all studies within 60 days after the study agreement has been executed. For any system impact study or facilities study completed during that quarter and more than 60 days after the study agreement was executed, the Commission proposed a penalty equal to $500 for each day the transmission provider takes to complete the study beyond 60 days. For any system impact study or facilities study that is still pending at the end of the quarter and that has been in the study queue for more than 60 days, the Commission proposed a penalty equal to $500 for each day the study has been in the study queue beyond 60 days.

1326. In addition to the proposed operational penalties, the Commission indicated that it would order other remedial actions, consistent with the Policy Statement on Enforcement, to be determined on a case-by-case basis. The Commission proposed that RTOs not be subject to this penalty regime because of the RTOs' independence.

Comments

1327. Transmission providers generally oppose the Commission's proposal.[800] Some opponents argue that, to the extent the Commission is going to impose penalties, it should do so on a case-by-case basis.[801] Opponents cite a number of reasons the Commission should not impose the proposed operational penalty regime. Several opponents caution that imposing a penalty may lead transmission providers to either prematurely deny a request or accept a request to the detriment of system reliability.[802] Several opponents argue that many transmission requests introduce unique complexities into the study process, so a firm 60-day deadline is not workable in practice.[803] Several opponents argue that the Commission's proposed penalty regime is inconsistent with the new requirements the Commission has proposed for regional planning and requirements to consider redispatch in the system impact study.[804] In its reply comments, EEI argues that due process requires that the Commission not impose penalties on transmission providers for study delays because, in EEI's view, it is highly likely that the delays will have been caused by factors or events that were beyond the transmission provider's control. Southern asserts that any scheme of operational penalties associated with the processing of studies cannot be implemented fairly unless and until the problem surrounding the submission of multiple requests is addressed. Southern argues that the Commission would violate a transmission provider's due process rights if it were to impose penalties for delays caused by transmission customers. CREPC proposes that transmission projects that cross seams not be subject to penalties, arguing that such an exception will create a level playing field for those transmission providers in the West working with the CAISO and foreign transmission owners to resolve transmission service requests.

1328. A number of commenters ask the Commission to clarify specific elements of the proposed operational penalty regime. Several commenters argue that the proposal does not clearly provide for an exemption from operational penalties if the failure to meet the timeliness criteria is a result of extenuating circumstances or customer caused delays, thereby denying transmission providers due process.[805] Several commenters ask the Commission to clarify that a transmission provider is not subject to operational penalties if the transmission provider's failure to meet the compliance threshold following its notification filing is due to extenuating circumstances.[806] Southern asks that the Commission clarify that the submission of a notification of extenuating circumstances would suspend the obligation of a transmission provider to process at least 90 percent of the study requests within the proposed deadlines, until such time as the Commission issues a final determination on the notification of extenuating circumstances. Tacoma asks the Commission to ensure that the processing time is measured from the point that the customer provides complete information.

1329. EEI recommends that the Commission hold a technical conference to determine the extent to which studies are not being completed within 60 days, the principal causes of delays in completing studies within 60 days and whether the increased planning and coordination requirements proposed by the Commission will result in additional time being needed to complete the studies. EEI believes the Commission is far more likely to arrive at a reasonable conclusion concerning these issues after a technical conference than if it simply imposes penalties for failures to complete all studies within 60 days. Seattle believes the proposed penalties should not be implemented until providers and customers have had at least one year of experience working with the performance metrics.

1330. Transmission customers generally support the Commission's proposal to impose operational penalties when a transmission provider routinely fails to meet the 60-day due diligence deadlines.[807] In its reply comments, Entegra argues that the question is not whether a transmission provider has sufficient margins of flexibility, but whether the transmission provider has any stake in meeting the deadlines. Occidental argues that transmission providers may have little incentive to meaningfully address customers' issues without the prospect of a prospective remedy. Responding to EEI's due process argument, TDU Systems in reply assert that imposition of penalties in this instance raises no more due process concerns than those operational penalties that transmission customers are routinely subjected to under the OATT. TDU Systems argue that, should the Commission determine that transmission providers are entitled to challenge any operational penalty for failure to process service requests in a timely manner, then those challenges must be on terms and conditions that are comparable to those available to transmission customers—a complaint pursuant to FPA section 206. TDU Systems believe that the proposed ''explanatory statement'' contemporaneous with any notification filing is a form of expedited review that is clearly not comparable to the treatment of customers under the tariff.

[799] The transmission provider would be deemed to be out of compliance if it completes 10 percent or more of non-affiliates' system impact studies and facilities studies outside of the deadlines prescribed in the *pro forma* OATT.

[800] *E.g.*, EEI, MidAmerican, Entergy, Southern, Imperial, NorthWestern, PNM–TNMP, Salt River, and Bonneville Reply.

[801] *E.g.*, EEI, Southern, and PNM–TNMP Reply.

[802] *E.g.*, MidAmerican, Southern, Imperial, and EEI Reply.

[803] *E.g.*, MidAmerican, Southern, NorthWestern, Northwest IOUs, and PNM–TNMP Reply.

[804] *E.g.*, MidAmerican, Southern, and EEI Reply.

[805] *E.g.*, EEI, Southern, Northwest IOUs, and MidAmerican.

[806] *E.g.*, EEI and MidAmerican.

[807] *E.g.*, Suez Energy NA, TAPS, Constellation, Entegra, TDU Systems, CREPC, and Nevada Companies.

1331. Several transmission customers question whether the proposed penalty level is sufficient to ensure compliance.[808] Constellation recommends a penalty of up to $10,000 per day per violation. Entegra suggests the Commission set the penalty equal to the higher of the lost opportunity cost to the customer resulting from the delay, if any, or $1,000 for each day. Entegra also suggests that penalties should be assessed automatically, without a notification filing to the Commission. In its reply comments, EEI argues that the total penalty for delayed studies will be far higher than $500 per day if the transmission provider is processing more than five requests per 60-day period, which EEI asserts is extremely likely.

1332. Constellation asks the Commission to consider whether to require the transmission provider to engage an independent transmission administrator to the extent a transmission provider's posted performance metrics are not accurate or the transmission provider persistently fails to adhere to the relevant timelines.

1333. Several commenters suggest that the Commission extend the study completion deadlines, such as to 120 or 180 days, at least for the purposes of assessing penalties.[809] Bonneville suggests that the Commission change the service request study process to match the interconnection study process as articulated in the Large Generator Interconnection Procedures. Imperial recommends that instead of mandating a nationwide study schedule, each of the NERC regions should establish a schedule taking into account the various needs of the region. Southern suggests restarting the 60-day due diligence period for any study that experiences a delay that cannot properly be attributed to the transmission provider. In contrast to the suggestions to increase the study time, Entegra suggests that the Commission consider changing the due diligence deadlines to 30 days to further the goal of encouraging timeliness in completing required studies.

1334. Several commenters suggest methods for distributing the operational penalties the transmission provider pays for late studies. TAPS believes that penalty revenues should go to victims of study delay. Similarly, Entegra believes the penalty should take the form of a credit against the transmission customer's obligation to reimburse the transmission provider for study costs, with any amount in excess of the study costs payable to the transmission customer, in recognition of the harm to transmission customers when required studies are not completed expeditiously. CREPC asks the Commission to clarify how it plans to determine which unaffiliated transmission customers will receive operational penalty payments. CREPC also asks the Commission whether the $500 per day penalty is a flat rate that would be pro-rated among eligible non-offending, unaffiliated transmission customers or if the $500 is a rate paid to each eligible transmission customer.

1335. Commenters affiliated with RTOs and one transmission customer support the Commission's proposal to exempt RTOs from penalties for late studies.[810] MISO asserts that RTOs do not have incentives to delay the processing of transmission service requests, as they have no affiliates to favor and because their Commission-approved design and internal procedures ensure their independence. MISO argues further that all transmission service requests benefit some RTO member and, as a result, RTOs have no disincentive to approve service so long as reliability is maintained. MISO/PJM States asserts that the NOPR proposal to exempt RTOs from operational penalties for late studies is appropriate because a penalty does not serve a useful purpose with respect to RTOs. TDU Systems state that an RTO should not be financially penalized for late studies because RTO independence should minimize incentives for affiliate preference and RTO members indirectly pay for all RTO incurred costs in any event.

1336. Most of those commenters not affiliated with an RTO oppose the proposal to exempt RTOs from penalties for late studies.[811] Southern argues that given that the Commission is seeking to increase transparency in the system, the Commission would undercut that goal by omitting a significant segment of the industry. TAPS argues that RTOs may still fail to complete studies on a timely basis due to competing internal priorities or bureaucratic indifference. Progress notes that the Commission has found that RTOs and ISOs should be subject to penalties for failure to meet reliability standards. Salt River argues that RTOs should be subject to operational penalties because the impact on the customer is identical if the request processing deadline is not met regardless of the type of provider conducting the study. Xcel notes that, historically, transmission owners need to complete facility studies in concert with RTOs, thereby giving the customer the most up-to-date and coordinated analysis. Consequently, Xcel believes it is imperative that both transmission owners and RTOs operate under the same rules, reporting obligations, and performance metrics in the OATT.

1337. In its reply comments, WPS disagrees with the Commission's proposal to exempt RTOs from penalties for their repeated failure to meet the 60-day due diligence requirements. WPS asserts that the Commission should impose penalties and prohibit the recovery of associated revenue where appropriate. WPS argues that RTO independence does not guarantee RTO competence or compliance in every instance. WPS believes imposing reporting obligations and penalties for failure to comply with tariff requirements, particularly tariff deadlines, will help to motivate compliance by ensuring that RTOs devote resources to tariff compliance. WPS acknowledges that a non-profit RTO has no dividends to cancel and likely no property to liquidate to cover these shortfalls, yet believes that such organizations can exercise cost-cutting measures, especially regarding rewards for employee performance, and thereby bear some financial responsibility and accountability for their operational violations. In the event of a penalty, WPS believes the Commission could require an RTO to take steps to cover its penalty-related revenue shortfall by cutting its budget, eliminating management bonuses and demonstrating that it has taken reasonable corrective steps before the Commission permits recovery of the remaining penalty revenue from its members and customers. To the extent some portion of an RTO's penalties are passed through to its market participants, including transmission owners, WPS argues that those market participants would be in a position to take actions similar to the actions taken by shareholders of a publicly traded company to motivate the RTO either by changing the RTO's processes or its Board of Directors.

1338. TAPS states that some adaptation of the penalties may be necessary to make them appropriate and effective in the non-profit RTO/ISO context, for example, by requiring a reduction in management compensation. TDU Systems recommend that RTOs be subject to the notification filing requirement that is part of the Commission's penalty

[808] *E.g.*, TAPS, Constellation, and Entegra.

[809] *E.g.*, Bonneville, MidAmerican, Progress Energy, NorthWestern, Northwest IOUs, and EEI Reply.

[810] *E.g.*, MISO, MISO/PJM States, TDU Systems, and Indianapolis Power Reply.

[811] *E.g.*, Southern, TAPS, Progress Energy, Salt River, and Xcel.

proposal, regardless of whether RTOs are subject to pay penalties. TDU Systems believe this reporting requirement would provide an objective measure of RTO efficiency. APPA believes steps should be taken to remedy tardy RTO processing of service requests, suggesting that performance incentives for RTO employees, if carefully designed, could be useful. In its reply comments, Duke argues that although transmission owners in RTOs should not pay the price for RTOs failures to abide by the tariff, RTOs lack of performance should be addressed by the Commission, perhaps in a separate proceeding.

1339. Transmission providers that have retained an independent tariff administrator suggest that these independent entities should also be exempt from operational penalties related to study completion times.[812] In their view, these independent entities also have no incentive to discriminate when completing service request studies. Similarly, NorthWestern argues that a transmission provider without an affiliate that could benefit from a delay in completing service request studies also should be exempt from paying the proposed operational penalties.

Commission Determination

1340. The Commission adopts the NOPR proposal to subject transmission providers to operational penalties when they routinely fail to meet the 60-day due diligence deadlines prescribed in sections 19.3, 19.4, 32.3 and 32.4 of the *pro forma* OATT. Transmission providers must have a meaningful stake in meeting study time frames. As discussed above, a transmission provider will be required to make a notification filing with the Commission indicating that it has not completed request studies on a timely basis and may present evidence that extenuating circumstances prevented it from completing studies on a timely basis. The transmission provider then will be subject to an operational penalty if the transmission provider continues to be out of compliance with the deadlines prescribed in the *pro forma* OATT for each of the two quarters following its notification filing and the Commission determines that no extenuating circumstances exist to excuse the transmission provider's non-compliance. The transmission provider will be deemed to be out of compliance if it completes 10 percent or more of non-affiliates' system impact studies and facilities studies outside of the deadlines prescribed in the *pro forma* OATT. The operational penalty will be assessed on a quarterly basis, starting with the quarter following the notification filing and continuing until the transmission provider completes at least 90 percent of all studies within 60 days after the study agreement has been executed. For any system impact study or facilities study completed during that quarter and more than 60 days after the study agreement was executed, the penalty will equal $500 for each day the transmission provider takes to complete the study beyond 60 days. For any system impact study or facilities study that is still pending at the end of the quarter and that has been in the study queue for more than 60 days, the penalty will equal $500 for each day the study has been in the study queue beyond 60 days.

1341. The late study penalty regime described in this Final Rule will become effective at the same time as the rest of the new *pro forma* OATT. The penalty regime is designed so that the transmission provider has to be out of compliance for at least three quarters before it is subject to late study penalties. We believe nine months is sufficient time for the transmission provider to adjust its operations to the new requirements in this Final Rule, including penalties for late studies. That is, we believe transmission providers should be able to reallocate employees to study requests for service and hire new staff, to the extent these steps are necessary, by the time the transmission provider will be subject to civil penalties.

1342. The procedures underlying the operational penalty regime adopted in this Final Rule ensure that the due process rights of transmission providers are protected. In their notification filing, transmission providers will have the right to document and describe any unique complexities that particular requests introduce into the study process and that prevent the transmission provider from completing the study within a the 60-day due diligence time frame. Thus the 60-day time frame will continue to be a flexible deadline, especially given that the transmission provider is not required to complete all studies within 60 days. These due process rights provide a de facto case-by-case review of the transmission provider's efforts to complete studies on a timely basis.

1343. On review of a notification filing, we will waive operational penalties if a transmission provider establishes that its non-compliance is the result of factors or events that are truly beyond its control, including delays caused by the transmission customer. We will not, however, exempt all transmission projects that cross seams from operational penalties, as CREPC urges. We will consider the specific facts surrounding studies of such projects based on a transmission provider's notification filing. In response to TDU Systems, we acknowledge that the procedures for addressing a transmission provider's failure to conform to the 60-day time frame are not the same as the procedures applicable to a transmission customer that is assessed an operational penalty under the *pro forma* OATT. We believe such different procedures are justified in this instance. The other operational penalties in the *pro forma* OATT are assessed for failure to remain in compliance with strict requirements, while the study time frame is based on the transmission provider using its due diligence to complete studies within 60 days. The Commission recognizes that the transmission provider must have flexibility, within reason, to complete studies outside of this time frame. At the same time, the notification and penalty procedures we adopt in this Final Rule will ensure that this flexibility is not abused.

1344. We do not find the remaining comments in opposition to the operational penalty for late studies to be compelling, particularly given the flexibility built into our penalty regime. We would not expect a transmission provider to prematurely deny a request for service simply to avoid an operational penalty. According to section 17.5 of the *pro forma* OATT, a transmission provider must either grant service or offer the transmission customer a system impact study. The transmission provider does not have the option to simply deny the request for service. We therefore interpret comments that the transmission provider may prematurely deny a request to mean that the transmission provider will not explore all possible system upgrades or redispatch options as required by section 19.3 of the *pro forma* OATT or any conditional firm options discussed in section V.D.1. Such behavior would be a tariff violation that should be brought to our attention. The transmission provider is required under the *pro forma* OATT to provide a complete study and corresponding work papers to the transmission customer. If a transmission customer feels a system impact study is incomplete, it has recourse to call the Commission's Enforcement Hotline or file a formal complaint with the Commission.

1345. We also do not expect a transmission provider to accept a

[812] *E.g.*, Duke, MidAmerican, and TranServ.

transmission service request to the detriment of system reliability simply to meet the study time frame. First, the transmission provider is not required to complete every request study within 60 days. Second, to the extent our new requirements that the transmission provider consider conditional firm options and participate in regional planning cause study delays, the transmission provider can document and describe such delays in its notification filing. Finally, the transmission provider has been required to consider redispatch in the system impact study since Order No. 888 was issued, so the 60-day due diligence time frame should continue to be consistent with the long standing requirement to consider redispatch in the system impact study.

1346. As we discuss below, we believe NAESB's queue hoarding and queue flooding business practices, as well as additional reforms adopted in this Final Rule, will address the problem surrounding the submission of multiple requests. With regard to requests for a technical conference or further procedures to consider the effect of our operational penalty regime, we believe the commenters' proposals would largely provide anecdotal information and speculation on the impacts of the new planning and coordination requirements. Our experience from the last ten years, and the comments provided in response to the NOI and NOPR, provide a sufficient basis to develop a penalty regime. In addition, the very requirement that transmission customers post performance metrics and submit notification filings prior to assessment of operational penalties will provide actual experience with the new regime. As explained above, the notification procedures adopted today will ensure that we will not assess a penalty for late studies unless justified by the circumstances. We can propose additional changes to the study process or penalty regime based on the actual experience under this Final Rule if our experience warrants it.

1347. As described above, we adopt the proposal to set the operational penalty for late studies equal to $500 per day per late study. We believe $500 per day per late study is in line with the cost the transmission provider would incur to focus additional resources on processing requests studies. In addition, the penalty for being one month late, $15,000, is in line with the overall cost of the study. We conclude that the $500 per day per late study penalty is high enough to provide the incentive to transmission providers to comply with study processing deadlines in the *pro forma* OATT, while not being unnecessarily punitive. We believe that a penalty in the range of $10,000 per day per late study would be unnecessarily punitive. The proposal to set the penalty equal to the higher of the lost opportunity cost to the customer resulting from the delay, if any, or $1,000 for each day is administratively cumbersome and could result in administrative costs that are not justified. Finally, we believe the due process afforded the transmission provider is an important element of the penalty regime, so we decline to impose penalties automatically, without a notification filing to the Commission.

1348. As indicated in the NOPR, we may order other remedial actions in addition to the operational penalties described above, consistent with the Policy Statement on Enforcement. We will determine any other remedial action on a case-by-case basis. The decision to order other remedial actions will be based, among other things, on whether we believe the transmission provider is using the same due diligence to complete studies for non-affiliated customers as it uses to complete studies for itself. We do not believe it would be appropriate, as a general matter, to require a transmission provider to engage an independent transmission administrator to the extent its posted performance metrics are not accurate. As a threshold matter, Commission audit staff may audit the accuracy of a transmission provider's posted metrics. If we are concerned about the accuracy of a transmission provider's metrics, we will evaluate the use of third-party audits at that time. We will not prejudge which remedial actions we will consider if a transmission provider persistently fails to adhere to the relevant timelines. Rather, we will review each such instance on a case-by-case basis and determine the appropriate remedial action consistent with the Commission's Policy Statement on Enforcement.

1349. We clarify that a transmission provider is not subject to operational penalties if it can make a showing that its failure to meet the compliance threshold following its notification filing is due to extenuating circumstances, as we agree that the transmission provider should not be penalized for factors out of its control. The submission of a notification of extenuating circumstances will not, however, suspend the obligation of a transmission provider to process at least 90 percent of the study requests within the proposed deadlines, until such time as the Commission issues a final determination on the notification of extenuating circumstances. At the same time, we will not require the transmission provider to distribute its operational penalty while we are still considering the transmission provider's notification filing. The transmission provider nonetheless remains liable for paying the operational penalty for all request studies completed or outstanding after the notification filing and not completed within 60 days. This timing will balance the transmission provider's due process rights with the need to provide an incentive to the transmission provider to complete studies on a timely basis.

1350. We clarify that the processing time is measured from the point that the customer returns its executed study agreement to the transmission provider. By the time the transmission provider offers a system impact study agreement, it should have all the information it needs to complete the study. Pursuant to section 17.4 of the *pro forma* OATT, the transmission provider can deem a transmission service request deficient if the transmission customer does not provide all information the transmission provider needs to evaluate the request for service. We expect the transmission provider to use informal means to communicate the information it needs from the transmission customer before it deems a transmission service request deficient.

1351. We adopt the NOPR proposal to have the transmission provider distribute the operational penalty for late studies to all non-affiliated transmission customers, as discussed in section V.C.5.b of this Final Rule. We believe that a transmission provider that is not processing studies on a timely basis potentially harms all transmission customers, not just those with requests in the study queue. For instance, a transmission customer may decide against requesting service that it believes will require a system impact study if the transmission provider is not processing transmission service requests on a timely basis. Therefore, we will not adopt suggestions to distribute penalty revenue only to transmission customers that have request studies that are not completed within 60 days. We clarify that the penalty is $500 per day per late study, with the resulting total penalty revenue distributed to unaffiliated transmission customers as discussed in section V.C.5.b of this Final Rule. We clarify that the transmission provider will propose a method to determine how unaffiliated transmission customers will receive operational penalty payments, as discussed in section V.C.5.b of this Final Rule.

1352. We will not alter the 60-day study completion timeframe currently embodied in sections 19.3, 19.4, 32.3 and 32.4 of the *pro forma* OATT. We continue to believe, absent concrete evidence to the contrary, that the existing timeframe adequately balances the need for expeditious resolution of request studies and the need to ensure that the transmission provider can reliably accommodate the transmission service reserved. Moreover, we believe the penalty regime defined in this Final Rule protects the transmission provider in the event studies take longer to complete due to the new planning requirements defined in section V.B of this Final Rule or the new requirement to consider conditional firm options as defined in section V.D.1 of this Final Rule. We will not adopt the suggestion to restart the 60-day due diligence period for any study that experiences a delay that can not properly be attributed to the transmission provider. We reiterate that the transmission provider is not subject to penalties for late studies if it can establish that delays are due to factors the transmission provider cannot control.

1353. The Commission declines to adopt the NOPR proposal to exempt RTOs from operational penalties for completing studies on an untimely basis. We agree with those commenters that argue that RTO independence does not guarantee RTO competence or compliance in every instance and that RTOs may fail to complete studies on a timely basis due to competing internal priorities or staffing issues. Imposing penalties for failure to comply with the due diligence timeframe for completing studies will provide RTOs an appropriate incentive to comply with the *pro forma* OATT requirements and ensure that they devote adequate resources to tariff compliance. Finally, we note that subjecting RTOs to operational penalties for late studies is consistent with the Commission's decision to subject RTOs and ISOs to penalties for failure to meet reliability standards.[813] We believe that all transmission providers, including RTOs, should operate under the same rules, reporting obligations, and performance metrics in the OATT. We will nonetheless keep in mind the nature of an RTO's operations and the RTO's unique characteristics when we consider whether penalties would be appropriate. We agree that RTOs do not have an incentive to discriminate (which is one of the bases for this policy) and we agree that imposing a penalty raises the issue of cost recovery, as most RTOs are not-for-profit entities. We will therefore consider these and all other relevant factors in exercising our discretion whether to impose a penalty in a given circumstance.

1354. Consistent with the treatment of RTOs, we will not exempt independent entities that provide tariff administration from penalties for late completion of studies. As with RTOs, independence does not guarantee competence or compliance in every instance. Independent entities have a similar incentive to limit the personnel committed to processing request studies in an effort to reduce overhead costs. We believe that all entities administering the tariff should operate under the same rules, reporting obligations, and performance metrics in the *pro forma* OATT.

(3) Recovery Through Rates

NOPR Proposal

1355. The Commission proposed that a transmission provider cannot recover for ratemaking purposes any operational penalty it pays for failing to process transmission service studies on a timely basis.

Comments

1356. CREPC noted that, while it may be reasonable for an investor-owned utility to pay penalties without being allowed to recover the penalties in rates, this approach will be problematic for utilities that do not have shareholders.

Commission Determination

1357. We will prohibit all jurisdictional transmission providers from recovering penalties for late studies from transmission customers. We believe that all entities administering the tariff should operate under the same rules, reporting obligations, and performance metrics in the *pro forma* OATT. Non-profit transmission providers have other sources of money to pay penalties beyond the revenue they collect for sales of transmission service. Therefore, we require non-profit transmission providers to pay operational penalties for late studies from their other sources of money. This notwithstanding, we may consider factors such as an entity's financial ability to absorb a penalty in determining whether to impose penalties in the first instance.

(4) Fee for Multiple Self-Competing Transactions

NOPR Proposal

1358. In the NOPR, the Commission sought comment on a fee structure that could provide a disincentive for transmission customers to submit duplicative requests without penalizing transmission customers that have legitimate requests for transmission service. The Commission asked for detailed recommendations, including any proposed tariff language, regarding the standards it should use to identify requests that would be subject to a fee. The Commission also sought recommendations on the level of a fee that balances its policy goals to discourage requests for transmission service that the transmission customer does not intend to confirm while not discouraging legitimate requests for transmission service. Finally, the Commission sought comment regarding the circumstances, if any, under which the processing fee would be refunded to or credited to the transmission customer.

Comments

1359. A number of commenters express support for a fee for duplicative requests.[814] CREPC believes that queue blocking behavior should be discouraged so that legitimate requests lower in the queue are not disadvantaged. MISO believes the transmission provider should be allowed to charge a fee that is small enough to not create a barrier to entry yet high enough to ''add up'' for anyone wishing to flood the queue. MISO and Seattle suggest that the fee be based on the transmission provider's cost to review a request and handle the initial processing. MISO also believes the transmission provider should be able to charge a fixed dollar amount for any accepted requests that the customer wants to retract. Southern suggests that the Commission consider a procedure whereby transmission customers place a deposit with transmission providers to cover a certain number of requests that is forfeited once the requests reach a certain threshold and are deemed self-competing. TranServ suggests that the fee apply to requests for long-term firm transmission service and be based on duration of the request and not capacity requested as an incentive to the transmission customer to submit fewer combined requests where possible. TranServ suggests this fee could be

[813] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672–A, 71 FR 19814 (Apr. 18, 2006), FERC Stats. & Regs. ¶ 31,212 at P 56 (2006) (''It is not arbitrary and capricious to treat all operators alike, including RTOs and ISOs, in terms of their liability for violation of a Reliability Standard.'').

[814] *E.g.*, MidAmerican, MISO, Seattle, Southern, TranServ, TAPS, and CREPC.

waived if the service request is submitted pre-confirmed.

1360. Most of the transmission customers and some transmission providers oppose the creation of a fee structure for duplicative requests for transmission service.[815] Several commenters argue that the Commission should determine whether the newly-adopted NAESB business practices and other reforms proposed in the NOPR can reduce the number of requests that the transmission customer does not intend to confirm.[816] Nevada Companies and Great Northern assert that the current deposit requirement serves to discourage multiple self-competing requests. Constellation asserts that the Commission should focus on narrowly-tailored penalties to deter market participants from intentionally jamming the queue.

1361. Several commenters suggest that a transmission provider that makes a showing that it is experiencing a significant problem with respect to customers' submission of multiple competing requests should be allowed to propose a fee to combat the problem.[817] MISO notes that the Commission has rejected a fee for unconfirmed requests in the past.[818]

1362. TAPS believes the fee revenue should be shared with network customers on a load-ratio share basis. TAPS also suggests that the fee apply to the transmission provider's merchant arm in a meaningful way.

1363. CREPC urges the Commission to adopt a simple, straightforward standard for determining duplicative requests, such as the same points of receipt and delivery, same source and sink, same time frame, and same firmness, as well as the same project at multiple locations. Powerex recommends that the Commission be very specific in describing the types of multiple transmission requests it believes to be a problem and the fee structure that would be applied to such problematic requests. For example, Powerex believes the Commission should clarify that requests subject to the fee must be multiple, not pre-confirmed, and with identical quantity, point of receipt, point of delivery, start time, end time, and firmness. In its reply comments, Santa Clara disagrees with Powerex. Santa Clara urges the Commission to examine the practice of queue hoarding and punish those entities that are acting in an anticompetitive and manipulative manner. Further, Santa Clara urges the Commission to refrain from being too specific in its ruling, as a more general explanation of the behavior to be avoided would go a long way in preventing entities from making an end-run around a ruling against queue hoarding.

1364. MidAmerican believes that if a fee is imposed, the fee should not be refunded as the administrative costs and difficulty of administering the refunds would be an unreasonable burden on the transmission provider. CREPC believes refunding or crediting the processing fee would defeat the purpose of having one in the first place, although the processing fee could be refunded if the duplicative service request attached to it actually comes to fruition. Suez Energy NA suggests that the processing fee be refunded whenever the transmission provider exceeds the 60-day request study due diligence deadline. TAPS suggests that the fee be structured to provide for exceptions where the failure to confirm reflects a legitimate purpose, not jamming. TAPS cites as examples transmission requests associated with requests for proposals, alternative sites for planned generation, and the inability to secure timely confirmation of all legs of a multi-system path. TAPS notes that the current *pro forma* OATT accommodates multiple submissions in relation to the same competitive solicitation in sections 19.2(ii) and 32.2(ii).

Commission Determination

1365. The Commission will not require transmission providers to charge a fee for duplicative requests for transmission service. We will instead first consider whether the newly adopted NAESB queue flooding and queue hoarding business practices reduce the number of requests that the transmission customer does not intend to confirm. We are concerned that benefits to market participants would not justify the administrative costs of a new fee if the NAESB business practices can effectively discourage transmission service requests the transmission customer does not intend to confirm. We also believe that the current deposit mechanism in section 17.3 of the *pro forma* OATT should have the same effect as a fee based on the transmission provider's cost to process the request for transmission service, like the fee MISO and CREPC propose. Pursuant to section 17.3, in the event a transmission customer retracts or withdraws a request, the transmission provider is allowed to deduct from the transmission customer's deposit the costs the transmission provider incurred to process the request. As a result, we do not believe any other fee structure is necessary to make the transmission provider whole when a transmission customer submits a transmission service request it does not expect to confirm.

1366. A transmission provider that continues to experience problems related to submission of multiple duplicative requests for transmission service is free to file a tariff modification that includes a fee to combat the problem. This filing should explain why the transmission provider is unable to handle the submission of multiple duplicative requests for transmission service through NAESB's queue hoarding and queue flooding business practices.

(5) Clustering Transmission Service Request Studies

NOPR Proposal

1367. In the NOPR, the Commission sought comment regarding whether a transmission provider should be required to study requests for transmission service in a group if the transmission provider fails to complete studies on a timely basis. If so, the Commission sought comment on the circumstances that should trigger such a requirement and the appropriate method of implementing the requirement. The Commission sought further comment regarding whether transmission providers should be required to study requests for transmission service in a group if all the transmission customers in the group agree to cluster their requests. Finally, the Commission sought comment regarding how to select the requests that belong to a cluster so that transmission customers cannot ''cherry-pick'' clusters to avoid transmission system upgrade costs.

Comments

1368. A few commenters, primarily transmission customers, believe transmission providers should be required to study requests for transmission service in a group.[819] CREPC believes transmission providers should have the discretion to develop the criteria for clustering so that transmission customers do not have the opportunity to ''cherry pick'' study clusters. If transmission providers are required to study requests in a group, Powerex believes customers should be

[815] *E.g.*, EEI, Nevada Companies, Powerex, and Suez Energy NA.

[816] *E.g.*, EEI, Powerex, Suez Energy NA, and Entegra.

[817] *E.g.*, EEI and TAPS.

[818] *See Midwest Independent Transmission System Operator, Inc.*, 97 FERC ¶ 61,269 (2001) (rejecting a proposal to include a fee for non-confirmed transmission service requests for firm point-to-point transmission service of one week or longer).

[819] *E.g.*, CREPC, Powerex, and Suez Energy NA.

given the option of paying the transmission provider to perform an individual study. Suez Energy NA believes studying requests that are clustered voluntarily will partially incorporate the value of counterflows in the study process. PGP believes transmission customers should have the opportunity to join a cluster, but only if the customer is bound to accept the study results.

1369. A number of commenters, primarily transmission providers, state that transmission providers should be allowed, but not required, to study requests for transmission service in a group.[820] Bonneville argues that the transmission provider is in the best position to determine whether requests should be studied individually or in groups. EEI asserts that clustering does not necessarily ensure timely completion of transmission studies. FirstEnergy believes each transmission service request should stand on its own merits and be directly assigned costs associated with its own request so that requests in one part of the request queue do not end up subsidizing requests in another part of the request queue. MISO believes giving the transmission provider discretion to cluster requests will address the Commission's concerns with respect to transmission customers cherry-picking clusters to avoid paying upgrade costs. Arkansas Commission and East Texas Cooperatives suggest that the Commission allow clustering through an open season procedure similar to the procedure SPP currently uses pursuant to Attachment Z of SPP's OATT.

Commission Determination

1370. The Commission will not require transmission providers to study transmission requests in a cluster, although we encourage transmission providers to cluster request studies when it is reasonable. We do, however, require transmission providers to consider clustering studies if the customers involved request the cluster and the transmission provider can reasonably accommodate the request. We believe clustering request studies offers potential benefits as the needed transmission upgrades are frequently large enough that the upgrade can accommodate more than one transmission service request. In addition, jointly modeling transmission service requests can allow the transmission provider to more efficiently design transmission system upgrades. Clustering also allows the transmission provider to include, to the extent it is consistent with good utility practice, the potential counterflows created by the clustered requests. We do not agree, as suggested by commenters, that clustering necessarily leads to one set of transmission customers subsidizing another set of transmission customers.

1371. We therefore require each transmission provider to include tariff language in its compliance filing that describes how it will process a request to cluster request studies and how it will structure the transmission customers' obligations when they have joined a cluster. We will give the transmission provider discretion to determine whether a transmission customer can opt out of a cluster and request an individual study. We are giving each transmission provider discretion to develop the clustering procedures it will use because we believe the transmission provider is in the best position to determine the clustering procedures that it can accommodate. We also believe that the transmission provider is in the best position to develop a clustering procedure that prevents a transmission customer from strategically selecting the clusters in which it participates in an attempt to avoid responsibility for needed transmission system upgrades.

(6) Standardization of Business Practices for Study Queue Processing

NOPR Proposal

1372. In the NOPR, the Commission sought comment on whether additional standardization of request queue processing is necessary. If so, the Commission sought comment on the specific issues commenters believe are not clearly prescribed in Order No. 676 or the NOPR and that require additional mandatory queue processing business practices.

Comments

1373. Several commenters identified issues where a transmission customer needs coordinated responses across several transmission systems in order to serve its load.[821] Seattle and NRECA suggest that the Commission amend the *pro forma* OATT so that a customer's applications for service across multiple systems that are intended to serve a single sink from an identified resource will be considered a single application for purposes of establishing the deadlines for rendering an agreement for service, revising queue status, eliciting deposits and finally commencing service. Seattle believes the Commission should permit coordination and implementation of these requirements by a third party such as wesTTrans.net and sub-regional planning organizations. At a minimum, these commenters ask the Commission to develop business practices to protect a transmission customer caught between two systems with uncoordinated deadlines.

1374. Exelon states that the Commission should require all transmission providers to allow transmission customers to link consecutive requests for service (*e.g.*, monthly firm service requests for December, January and February) and to evaluate such request as a single request. Exelon argues that this service, which is currently provided by some transmission providers, would increase uniformity and use of the transmission system, and enhance competitiveness without burdening transmission providers or adding administrative complexity.

1375. TDU Systems indicate that several of its members have experienced difficulty related to the lack of standardized business practices, particularly in practices related to timing, application requirements, and requirements relating to methods of proving that a network customer has executed a power purchase agreement prior to designating the power purchase agreement as a network resource.

1376. PNM–TNMP does not believe that additional clarity or business practices are necessary beyond those already provided in Order No. 676. However, to the extent additional issues arise, PNM–TNMP believes NAESB's WEQ forum is the appropriate place to address them. Similarly, NorthWestern recommends that transmission providers work together within regional groups to develop a common set of business practices that will be followed by all transmission providers within each region, instead of the Commission using the NOPR comments it receives to develop a prescriptive set of business practices by which all transmission providers must abide. In its reply comments, Powerex argues that either the entire transmission process has to be integrated via an RTO, or coordination of requests across multiple control areas has to be done transmission provider by transmission provider. Powerex suggests that NorthWestern's suggestion for regional development of business practices may be a more pragmatic approach to address concerns about coordination of requests across multiple systems.

[820] *E.g.*, Bonneville, EEI, MISO, Nevada Companies, Southern, Entegra, and PNM–TNMP.

[821] *E.g.*, NRECA, TDU Systems, and Seattle.

Commission Determination

1377. The Commission agrees that transmission requests across multiple transmission systems should be coordinated by the relevant transmission providers. We will not, however, amend the *pro forma* OATT to require such coordination. Rather, we require transmission providers working through NAESB to develop business practice standards related to coordination of requests across multiple transmission systems. In order to provide guidance to NAESB, we will articulate the principles that should govern processing across multiple systems. All the transmission providers involved in a request across multiple systems should consider a request that requires studies across multiple systems to be a single application for purposes of establishing the deadlines for rendering an agreement for service, revising queue status, eliciting deposits and commencing service. In order to preserve the rights of other transmission customers with studies in the queue, the priority for the single application should be based on the latest priority across the transmission providers involved in the multiple system request. We note that regional entities like wesTTrans are already coordinating requests across multiple transmission systems and we believe such coordination is an acceptable solution to this issue.

1378. We interpret Exelon's request that we require all transmission providers to allow transmission customers to link consecutive requests for firm point-to-point transmission service and to evaluate such requests as a single request as asking us to (1) allow transmission customers to require the transmission provider to either grant service for the entire period, deny service for the entire period, or offer the same partial quantity for the entire period and (2) require the transmission provider to consider the full duration of the linked requests when determining reservation priority pursuant to sections 13.2 of the *pro forma* OATT (short-term firm point-to-point transmission service). We require transmission providers working through NAESB to develop business practice standards to allow a transmission customer to rebid a counteroffer of partial service so the transmission customer is allowed to take the same quantity of service across all linked transmission service requests. Transmission providers need not implement these business practice standards until NAESB develops appropriate standards. We note that the transmission customer should not be required to take the same quantity of service across consecutive transmission service requests, it should simply have the option to do so. On the second issue, we reiterate that, according to existing NAESB business practice standard 001–4.16, the transmission provider is required to consider the full duration of the linked requests when determining reservation priority pursuant to section 13.2 of the *pro forma* OATT.

1379. We believe most of the standardization issues TDU Systems raise (application requirements, requirements relating to methods of proving that a network customer has executed a power purchase agreement prior to designating the power purchase agreement as a network resource, and timing) have been addressed in this Final Rule. In particular, we describe the information a network customer is required to provide when designating a new network resource in section V.D.6.b of this Final Rule. We also indicate in section V.D.6.b that the transmission provider is not allowed to require a network customer to provide contract terms and conditions when it designates a power purchase agreement as a network resource. The network customer is required to provide a statement that attests, among other things, that it has executed a power purchase agreement prior to confirming its request to designate a new network resource. We will continue to give transmission providers discretion in determining whether to impose restrictions on the earliest time at which it will accept a request for transmission service. We believe the transmission provider is in the best position to determine whether it needs to restrict the time at which it will accept requests for transmission service in order to process transmission service requests in an orderly fashion consistent with the requirements in the *pro forma* OATT.

(7) Additional Processing Proposals

Comments

1380. A number of commenters propose changes to queue processing requirements that were not addressed in the NOPR.

1381. Powerex believes that OASIS practices should be modified to ensure that short-term firm and non-firm point-to-point service requests are processed based on the ATC posted at the time the requests were queued. Powerex argues that a transmission provider should not be permitted to grant transmission service requests at a time when its OASIS indicates there is no ATC. In its view, any such requests should be automatically denied. Powerex also suggests that confirmation time periods be shortened for short-term firm point-to-point service requests to discourage behaviors that have the effect of delaying queue processing. In its reply comments, Powerex asserts that requiring transmission provider responses to be based on posted ATC, as well as increasing standardization in transmission provider response time for short-term transmission requests, would enhance a transmission customer's ability to manage multiple transmission provider requests within the context of the *pro forma* tariff.

1382. Occidental suggests in reply that the Commission should introduce meaningful tariff-based sanctions for unauthorized deviations from the standards and modeling assumptions it proposes to include in Attachment C of the *pro forma* OATT, the transmission provider's description of its ATC calculation methodology.

1383. Several commenters make suggestions to allow the transmission provider to terminate idle transmission service requests. TDU Systems recommends that the Commission provide a sunset date by which all requests not pursued by the transmission customer would be terminated. MidAmerican and Northwest IOUs ask the Commission to clarify in the Final Rule that the transmission provider may deem a transmission service application withdrawn and terminated if a customer revises its application or if such customer fails to timely pay the annual reservation fee pursuant to section 17.7 of the *pro forma* OATT.

1384. Constellation asks the Commission to require transmission providers to release study results as soon as a study is completed, rather than holding them until the end of the 60 days.

1385. NorthWestern believes an appropriate modification to the study process would be to allow the transmission provider to have an opportunity to verify and correct the system impact study results at the beginning of the facilities study and again before construction begins.

1386. With the exception of very short-term transmission service (for which a bid-based system is impractical to manage), LDWP suggests that the queue process be transformed into a competitive process in which awards of transmission service are allocated in a manner similar to the provisions in section 4.4 of Order No. 638.

1387. TranServ notes that OASIS standards allow the customer to turn a request into a pre-confirmed request, but not vice versa. If the Commission's

proposal on granting priority to pre-confirmed requests is adopted, TranServ believes this capability should be removed from OASIS as it would seem to invite gaming and confuse transmission providers attempting to process requests in proper queue order.

1388. PGP states that OASIS platforms should be accessible from different computer platforms using a variety of browsers, not just one operating system/browser combination (Windows/Explorer), which is currently the case.

Commission Determination

1389. We will not adopt Powerex's proposal to require the transmission provider to accept or deny in all cases non-firm and short-term firm point-to-point transmission service requests solely based on posted ATC. The issue Powerex raises is ultimately a question of how the transmission provider is going to exercise its discretion under the tariff. Under the *pro forma* OATT, the transmission provider can use its knowledge of the system to exercise its discretion to offer transmission service even if posted ATC is not sufficient to accommodate the requested service. Alternatively, the transmission provider can use its discretion to update posted ATC in response to a transmission customer's verbal request to update ATC.[822] In both situations, the transmission provider may provide transmission service in instances when posted ATC is not sufficient to accommodate a transmission service request at the time the transmission customer requests service. We do not wish to discourage transmission providers from making transmission service available at times when posted ATC is not accurate. Therefore, we will continue to allow the transmission provider to accept transmission service requests in instances when posted ATC is not sufficient but the transmission provider believes it can accommodate the service. The transmission provider must use its discretion to grant service when posted ATC is not sufficient on a non-discriminatory basis. In order to ensure that it does so, we expect the transmission provider to log such instances as an act of discretion and post the log as required in section 37.6(g)(4) of the Commission's regulations.[823]

1390. We will not modify the *pro forma* OATT to address requests to allow the transmission provider to terminate idle transmission service requests. NAESB's business practice 001–4.11 allows the transmission provider to retract a request if the transmission customer does not respond to an acceptance within the time established in NAESB business practice standard 001–4.13. Therefore, we interpret TDU Systems comments to refer to circumstances when a transmission customer fails to respond to the transmission provider's request for additional information during the course of a request study. As discussed above, by the time the transmission provider offers a system impact study agreement, it should have all of the information that it needs to complete the study. Pursuant to section 17.4 of the *pro forma* OATT, the transmission provider can deem a transmission service request deficient if the transmission customer does not provide all of the information the transmission provider needs to evaluate the request for service. We will revise section 17.7 of the *pro forma* OATT so that the transmission provider is able to terminate a request for transmission service if a transmission customer that is extending the commencement of service does not pay the required annual reservation fee within 15 days of notifying the transmission provider that it would like to extend the commencement of service. We will not change the *pro forma* OATT to allow the transmission provider to terminate a transmission service request if the transmission customer changes its application for service. We believe the existing *pro forma* OATT is sufficient to allow a transmission provider to manage situations where the transmission customer modifies its application for service to the point that the customer is requesting transmission service that is meaningfully different than its initial request.

1391. We clarify that sections 19.3 and 32.3 of the *pro forma* OATT require the transmission provider to release study results as soon as a study is completed, rather than holding them until the end of the 60 days.

1392. Commenters also suggest changes to the OASIS protocols, including prohibiting transmission customers from changing a request into a pre-confirmed request and requiring OASIS platforms to be accessible on non-Windows/Explorer computers. We believe these issues are best addressed by NAESB.

1393. Commenters proposed a number of additional modifications to the *pro forma* OATT that we do not believe are necessary. These proposals would (1) allow the transmission provider to verify and correct studies between each step in the study process, (2) transform the queue process into competitive process, (3) shorten the confirmation time periods for short-term firm point-to-point service requests and (4) introduce penalties when the transmission provider deviates from the ATC calculation procedures detailed in Attachment C of the *pro forma* OATT. We believe the *pro forma* tariff is just and reasonable without such modifications and the commenters have not demonstrated that reforms in these areas are required at this time to prevent the exercise of undue discrimination.

b. Reservation Priority

1394. Section 13.2 of the *pro forma* OATT requires transmission providers to process requests for long-term firm point-to-point service on a first-come, first-served basis and to process requests for short-term firm point-to-point service on a first-come, first-served basis conditional on the duration of the request. Section 14.2 of the *pro forma* OATT requires transmission providers to process requests for non-firm point-to-point service on a first-come, first-served basis conditional on the duration of the request to the extent transmission capacity beyond that needed by native load customers, network customers and firm point-to-point transmission customers is available. In the NOPR, the Commission made a number of proposals and requested comment regarding various aspects of the reservation priority rules.

(1) Priority for Pre-confirmed Requests

NOPR Proposal

1395. In the NOPR, the Commission proposed to change the priority rules to give priority to pre-confirmed requests for firm point-to-point transmission service. Specifically, the Commission proposed that a pre-confirmed short-term request for firm transmission service would preempt any non-pre-confirmed short-term requests, regardless of duration. Similarly, the Commission proposed that a pre-confirmed request for long-term firm transmission service would preempt a request for long-term transmission service that is not pre-confirmed. Under the Commission's proposal, a pre-confirmed request for short-term transmission service would not pre-empt a non-pre-confirmed request for long-term transmission service.

Comments

1396. A number of commenters generally support the Commission's proposal to give priority to pre-

[822] *See, e.g.*, *Florida Power Corp.*, 111 FERC ¶ 61,243 at P 5 (2005).

[823] 18 CFR 37.6(g)(4).

confirmed requests.[824] Commenters who support the proposal note that giving reservation priority to pre-confirmed requests for transmission service could help alleviate the problems that arise when a transmission customer submits multiple identical requests for service with no intention of confirming all accepted requests.[825] Supporters of the proposal also note that the proposal would allow the transmission provider to focus its attention on those requests that appear most likely to result in an actual reservation of transmission service.[826] Although Nevada Companies do not oppose the proposal, they note that concerns regarding withdrawal of pre-confirmed requests might otherwise be alleviated by requiring a non-refundable deposit on requests.

1397. Several commenters suggest that establishing reservation priority first based on pre-confirmation status and then based on duration would ultimately result in transmission customers with relatively shorter term requests getting transmission service instead of transmission customers with relatively longer term requests.[827] EEI asserts that this result would be inconsistent with the Commission's desire to promote longer-term uses of the transmission system. Several transmission providers suggest that the Commission modify its proposal to ensure that longer duration requests continue to have a priority over shorter duration requests.[828] EEI suggests that the Commission should use pre-confirmation as a tie-breaker for short-term requests for transmission service with the same duration. Southern argues further that a pre-confirmed daily or hourly request should not preempt a weekly request that has not been pre-confirmed.

1398. Opponents of the proposal identify a number of operational difficulties in implementing a system that gives priority to pre-confirmed requests. Several commenters note that transmission customers are not bound to take service because they pre-confirm a request for transmission service.[829] They argue, for instance, a transmission customer is not bound to take service in the event the transmission provider offers a study or counteroffers the request with a partial quantity of service. Similarly, MidAmerican notes that a transmission customer may withdraw a pre-confirmed request for transmission service at any time prior to acceptance by a transmission provider. Opponents also argue that giving priority to pre-confirmed requests would disrupt the study process.[830] This disruption would occur when a transmission provider receives a pre-confirmed request for transmission service while it is actively studying a request for service that has not been pre-confirmed. Under these circumstances, the transmission provider would be required to suspend the study of one request in order to study a request with a higher reservation priority. In its reply comments, Indianapolis Power asks the Commission to clarify if this interpretation of the NOPR proposal is accurate. TranServ, suggesting that the Commission has not proposed to give a priority to pre-confirmed requests for non-firm transmission service, asserts that having different priority rules for firm and non-firm transmission service introduces unnecessary complexity. Finally, Southern believes that a pre-confirmed service request submitted within close proximity to the actual commencement of service should not preempt an existing non-pre-confirmed request, if doing so would be disruptive to the operations of the transmission provider or to the reliability of the system itself.

1399. Opponents also argue that giving a priority to pre-confirmed requests would unfairly disadvantage transmission customers who are not in a position to pre-confirm their requests, such as those requesting service in response to a request for proposals.[831] EEI notes that the Commission addressed this issue when it issued Order No. 638 and decided that giving priority to pre-confirmed requests would disadvantage customers who are requesting service from multiple transmission providers.[832] In the event the Commission decides to proceed with its proposal, TAPS suggests that the Commission limit the priority for pre-confirmed requests to non-firm and short-term firm requests for transmission service.

1400. Several commenters question whether a request that has been accepted but not confirmed would be pre-empted by a new pre-confirmed request.[833] In a similar vein, TDU Systems suggests that the Commission include a time window between acceptance of a request and confirmation of the request, during which a request can not be preempted by a pre-confirmed request for transmission service.

Commission Determination

1401. The Commission generally agrees with those commenters that argue that giving a priority to pre-confirmed requests can increase the efficient utilization of the system by giving priority to customers who are committed to purchase service over those who have not so committed, including customers that submit multiple requests without any intent to take service if each request is granted. However, we are mindful of concerns that doing so could undermine the Commission's desire to promote longer-term uses of the transmission system, disrupt the study process, or disadvantage transmission customers that are not in the position to pre-confirm their requests. As a result, we will modify the NOPR proposal and give priority only to pre-confirmed non-firm point-to-point transmission service requests and short-term firm point-to-point transmission service requests. In addition, longer duration requests for transmission service will continue to have priority over shorter duration requests for transmission service, with pre-confirmation serving as a tie-breaker for requests of equal duration. This policy will still give an advantage to pre-confirmed requests without imposing substantial implementation difficulties or undermining the Commission's goals to encourage longer-term uses of the transmission system. Our revised policy on priority for pre-confirmed requests thus addresses the comments that we should preserve the priority of longer duration requests for transmission service over shorter duration requests for transmission service. For instance, a pre-confirmed daily or hourly request will not preempt a weekly request that has not been pre-confirmed. Pre-confirmed short-term service requests therefore will *not* have a priority superior to that of long-term service requests that have not been pre-confirmed.

1402. We acknowledge that our revised policy on priority for pre-confirmed requests may be less effective than the NOPR proposal in alleviating the problems that arise when transmission customers submit multiple identical requests for service. However, we have taken other steps—notably accepting the NAESB business practices on queue flooding and queue

[824] *E.g.*, Nevada Companies, Seattle, LDWP, PGP, PNM–TNMP, Salt River, and Suez Energy NA.

[825] *E.g.*, Ameren, Santa Clara, Entegra, Entergy, and TVA.

[826] *E.g.*, Ameren and NorthWestern.

[827] *E.g.*, CREPC and EEI.

[828] *E.g.*, Entergy, Southern, and NorthWestern.

[829] *E.g.*, Bonneville and EEI.

[830] *E.g.*, Bonneville, EEI, and MidAmerican.

[831] *E.g.*, EEI, MISO, TAPS, Constellation, and TDU Systems.

[832] *Open Access Same-Time Information System and Standards of Conduct*, Order No. 638, 65 FR 17370, FERC Stats. & Regs., ¶ 1996–2000 ¶ 31,093 at 31,439 (2000).

[833] *E.g.*, MidAmerican and TranServ.

hoarding[834]—that we believe will substantially reduce the instances of multiple identical requests for service.

1403. The Commission also acknowledges the concerns expressed regarding operational difficulties caused by giving priority to pre-confirmed requests and clarify our policy as follows. First, we will prohibit transmission customers from withdrawing pre-confirmed non-firm and short-term firm point-to-point transmission service requests prior to when the transmission customer is offered service or a system impact study. This policy will address MidAmerican's concern that a transmission customer may withdraw a pre-confirmed request for transmission service at any time prior to acceptance by a transmission provider. We believe prohibiting withdrawal of a pre-confirmed request is less administratively burdensome than the non-refundable deposit on requests proposed by Nevada Companies and achieves the same goals. The Commission will allow transmission providers to invalidate a pre-confirmed request at the request of the transmission customer in the very near term following submittal of the request, in the event the transmission customer makes an inadvertent error in submitting its request. We expect the transmission provider to log such occurrences as an act of discretion so we can verify that transmission customers are not abusing this flexibility.

1404. Second, while the Commission recognizes that a customer submitting a pre-confirmed request is not bound to take service when the transmission provider counteroffers the transmission customer's initial request, we do not believe this fact alone warrants reversing our proposal to give a priority to pre-confirmed requests. We are satisfied that a transmission customer that pre-confirms its request is obligated to take full service in the event the transmission provider offers the service requested.

1405. The Commission also believes the revised priority policy will address Southern's comment that a pre-confirmed service request submitted within close proximity to the actual commencement of service should not preempt an existing non-pre-confirmed request if doing so would be disruptive to the operations of the transmission provider or to the reliability of the system itself. A pre-confirmed request for transmission service will not pre-empt an equal duration request that has already been confirmed. Therefore, the effects of the priority for pre-confirmed requests will be resolved prior to the time when the transmission provider would require an accepted request to be confirmed. Handling priority for pre-confirmed requests should be no more disruptive than giving a transmission customer time to confirm an accepted request.

1406. Excluding long-term requests for transmission service will mitigate many of the concerns expressed by commenters who argued that giving a priority to pre-confirmed requests will unfairly disadvantage transmission customers who are requesting service in response to a request for proposals and are therefore not in a position to pre-confirm their requests. Such requests for proposals typically involve long-term contracts for energy and/or generating capacity and, therefore, would be linked most likely to long-term transmission service requests. We disagree, however, with EEI's characterization of the Commission's decision in Order No. 638 to give a priority to pre-confirmed requests for non-firm service only if the request offers a higher price. The Commission's decision in that proceeding was driven by its interpretation that the proposed business practice addressed in the part of Order No. 638 cited by Southern was not consistent with the relevant section of the *pro forma* tariff. In addition, the Commission's experience since Order No. 638 and the comments received to the NOPR proposal indicate the value of giving a priority to pre-confirmed requests, despite concerns that some transmission customers are not in a position to pre-confirm their requests for transmission service.

1407. In response to requests for clarification from MidAmerican and TranServ, we clarify that a new pre-confirmed request for transmission service would preempt a request of equal duration that has been accepted by the transmission provider but not yet confirmed by the transmission customer. Thus, we decline to adopt TDU Systems' suggestion that the Commission include a time window between acceptance of a request and confirmation of the request, during which a request can not be preempted by a pre-confirmed request for transmission service. This is consistent with our desire to give transmission service first to those customers that are committed to taking the transmission service if it is granted. In the case of monthly firm point-to-point transmission service, the transmission customer has up to four days to confirm an accepted request. This is a potentially long delay when there is another transmission customer that is willing to commit to take the same service. Moreover, this policy is consistent with NAESB business standard 001–4.25, which allows a pre-confirmed request for non-firm point-to-point transmission service to preempt a request of equal duration and lower price that has been accepted but not confirmed.[835]

(2) Price as a Tie-Breaker

NOPR Proposal

1408. The NOPR also proposed to add price as a tie-breaker in determining reservation queue priority when the transmission provider is willing to discount transmission service. Under the Commission's proposal, price would serve as a tie-breaker after pre-confirmation for those requests that are not yet confirmed.

Comments

1409. All of the commenters who address the Commission's proposal to add price as a tie-breaker support the proposal, although some request that it be modified or clarified. Several commenters ask the Commission to clarify that an otherwise higher queued request has a right to match the price offer of a request with a higher price.[836] With regard to short-term service, WAPA believes that the Commission's proposal to add price as a tie-breaker would overly complicate matters after taking into account the many complex timing restrictions on short-term service. As a result, WAPA proposes that the Commission limit application of its proposal to requests for long-term transmission service. MISO/PJM States suggest that the Commission consider requiring point-to-point transmission customers to offer a reservation price at which they would be willing to sell their transmission service.

Commission Determination

1410. The Commission adopts the NOPR proposal to add price as a tie-breaker in determining reservation queue priority when the transmission provider is willing to discount transmission service. As a result, price will serve as a tie-breaker after pre-confirmation for those requests that have not yet been confirmed by the transmission customer or have not yet been evaluated by the transmission provider. Consistent with the principles currently embodied in the *pro forma* OATT and articulated in Order No. 638, we clarify that, in the event a later queued short-term request for

[834] *See* Order No. 676 at P 19.

[835] *See* Order No. 676.

[836] *E.g.*, EEI and MidAmerican.

transmission service preempts a conditional confirmed short-term request for transmission service based on price, then the conditional confirmed request has a right to match the price offer of the later queued request.[837]

1411. We disagree with WAPA's proposal to limit application of the NOPR proposal to requests for long-term transmission service. We believe the addition of price as a tie-breaker for discounted firm point-to-point transmission service is an economically efficient policy for both short-term and long-term firm point-to-point transmission service. We recognize that adding another element to the reservation priority criteria adds additional complexity. However, we believe that the efficiency gains warrant any additional complexity in the few cases in which transmission customers bid for transmission service.

1412. We do not agree with MISO/PJM States' suggestion that the Commission require point-to-point transmission customers to offer a reservation price at which they would be willing to sell their transmission service. The transmission provider may already make unscheduled firm transmission service available to other customers on a non-firm basis and we have adopted proposals that we believe will encourage transmission customers to voluntarily offer to sell firm point-to-point transmission service on the secondary market as described in section V.C.4 of this Final Rule. As a result, we see no reason to require a firm point-to-point customer to offer its reserved capacity for sale.

(3) Five-Minute Window for Requests

NOPR Proposal

1413. In the NOPR, the Commission responded to comments that transmission customers that have the financial resources to purchase software and employ staff to continually monitor OASIS sites have an unfair advantage under a first-come, first-served approach by seeking comment on whether any such advantage would be mitigated if all requests submitted within a five-minute window were deemed to have been submitted simultaneously. The Commission also sought comment on whether transmission customers could game a five minute equivalent priority standard to request transmission service only after another transmission customer has made a request. The Commission further sought comment on how to allocate limited transmission capacity among equivalent priority requests of equal duration, in the event a five minute equivalent priority standard is adopted.

Comments

1414. Many of the commenters in the West support the proposal to treat transmission requests submitted within some specified period of time as submitted simultaneously. Supporters of a time window within which all requests would be deemed to have been submitted simultaneously argue that the proposal would give transmission customers who are less sophisticated and have fewer financial resources equal access to transmission service.[838] Other supporters argue that such a time window would be particularly appropriate in circumstances when a tariff calls for requests to be submitted ''no earlier than'' a specific deadline.[839] In its reply comments, NRECA argues that a customer attempting to plan a request under such circumstances may miss being the first in time by a matter of seconds because its computer is slower than another customer's computer.

1415. Supporters of the proposal suggest a number of modifications to the Commission's suggested five-minute window. A number of commenters suggest a window longer than five minutes.[840] For instance, Bonneville proposes a system similar to PJM's 30 minute window for monthly service. On the other hand, Manitoba Hydro suggests a shorter window and a limit on the number and size of requests, claiming this would reduce the potential for gaming and/or anti-competitive behavior. A number of commenters also suggest that such a system should be limited to short-term transmission service[841] and/or should not apply to requests for transmission service submitted close to the hour that service commences.[842] In its reply comments, PNM–TNMP asserts that, if the Commission implements a five-minute window policy, then the policy should not be limited to long-term transactions. In its reply comments, NRECA argues that requests submitted within a five-minute window should not be publicly available until the window has closed in order to prevent competitors from requesting the same service simply to disrupt the transmission service procurement process. Similarly, Bonneville suggests that the reservation process should be conducted like a blind auction, so that requests are not visible on OASIS until the window closes.

1416. Many of the large power marketers and transmission providers in the East oppose the notion of a submittal window. Opponents of a time window within which all requests would be deemed to have been submitted simultaneously suggest that the proposal is an unnecessary complication and may actually be counterproductive to the Commission's ultimate goal due to issues regarding how transmission service would be allocated among simultaneous requests.[843] EEI notes that there is no limit on how far in advance a transmission customer may submit requests for firm transmission service, so the likelihood that any two requests are submitted within the same five minute period is low. Powerex argues that the simplicity of the first-come, first served approach limits the number of disputes. In its reply comments, Powerex argues that none of the commenters that favor a five-minute window addressed the operational problems that such a proposal would generate.

1417. Some commenters argue that a *pro rata* allocation of simultaneous requests of equal duration will result in all transmission customers acquiring less transmission service than they need to complete their wholesale transactions.[844] As a result, these commenters suggest that the need to provide transmission customers with usable quantities of transmission service will necessarily lead to developing an allocation protocol in addition to allocating based on time submitted and duration of request.[845] Powerex argues that any system that creates a time window within which all requests would be deemed to have been submitted simultaneously will lead transmission customers to inflate the quantity of service they request in order to get quantity of service they actually desire. Other commenters make suggestions regarding the manner by which transmission service should be allocated among simultaneously submitted requests. Bonneville believes that each transmission provider should develop an allocation method appropriate to its system. CREPC suggests that price be used as a secondary tie-breaker after duration. TDU Systems argue that using duration

[837] *See* Order No. 638 at 31,442.

[838] *E.g.*, Bonneville and Santa Clara.

[839] *E.g.*, TDU Systems and NRECA.

[840] *E.g.*, Bonneville and CREPC.

[841] *E.g.*, Bonneville and Nevada Companies.

[842] *E.g.*, Bonneville and NRECA.

[843] *E.g.*, EEI, MidAmerican, Ameren, Constellation, Entergy, NorthWestern, PNM-TNMP, WAPA, Powerex, and Indianapolis Power Reply.

[844] *E.g.*, Powerex and TranServ.

[845] *Id.*

as a tie-breaker for simultaneous requests could discriminate against purchased power contracts that are designated as network resources.

Commission Determination

1418. Based on the comments received, it appears that the desire for a time window within which all requests would be deemed to have been submitted simultaneously is largely limited to market participants in the Western Interconnection. With one exception, we will not mandate a change to our current first-come, first-served policy to address an issue that appears to be regional in nature. Rather, we will allow transmission providers to propose a window within which all transmission service requests the transmission provider receives will be deemed to have been submitted simultaneously. Transmission providers will have discretion to determine which transmission services will be subject to a submittal window policy. We believe the transmission provider is in the best position to determine whether it can accommodate a submittal window for a specific transmission service and the need for such a window.

1419. In order to ensure that transmission service is not awarded in an arbitrary fashion and to ensure that transmission customers who are less sophisticated and have fewer financial resources have equal access to transmission service, we will require transmission provider who set a ''no earlier than'' time for request submittal to treat all transmission service requests received within a specified period of time as having been received simultaneously. We agree with those commenters that argue that a time window within which all requests would be deemed to have been submitted simultaneously is particularly appropriate in circumstances when a tariff or business practice calls for requests to be submitted no earlier than a specific deadline. As NRECA argues, there is no meaningful difference between requests for transmission service that are identical in all respects except that one request is received by the transmission provider seconds ahead of another request because one customer's computer is slower than another customer's computer. EEI is correct that NAESB's uniform business practices do not limit how far in advance a transmission customer may submit requests for firm transmission service.[846] However, a number of transmission providers have modified their tariffs or adopted business practices that mandate that requests can be submitted no earlier than a specific deadline.[847] In these instances, multiple requests for transmission service can be submitted at approximately the same time. We generally agree with Powerex's assertion that the simplicity of the current first-come, first served approach limits the number of disputes. However, when a transmission provider establishes a ''no earlier than'' deadline, submittals that are received by the transmission provider within a matter of seconds cannot be meaningfully differentiated. A transmission provider with such a business practice or tariff provision will be required to modify its tariff to include its proposed specified period of time. We will evaluate each proposal on a case-by-case basis, as described below.

1420. We will allow transmission providers to propose the period of time within which all requests would be deemed to have been submitted simultaneously. We believe the transmission provider is in the best position to identify the window it can operationally accommodate. We expect the submittal window to be open for at least five minutes unless the transmission provider can present a compelling rationale to justify a shorter submittal window.

1421. We agree with NRECA and Bonneville's suggestion that requests submitted within a specified window should not be publicly available until the window has closed in order to prevent competitors from requesting the same service simply to disrupt the transmission service procurement process.

1422. We will require each transmission provider that is required to, or decides to, deem all requests submitted within a specified period as having been submitted simultaneously to propose a method for allocating transmission capacity if sufficient capacity is not available to meet all requests submitted within the specified time period. We agree with Bonneville that the transmission provider is in the best position to determine an allocation that is appropriate to its system and that cannot be gamed in the manner suggested by Powerex and TranServ. We believe that transmission providers will be able to develop allocation methods, like the method PJM uses to allocate monthly firm point-to-point transmission service, that address the operational issues Powerex and TranServ raise.

(4) Right of First Refusal and Preemption

1423. While not specifically addressed in the NOPR, a few commenters use the Commission's proposed introduction of hourly firm service, discussed above, to argue that the Commission should take the opportunity to clarify or revise the right of first refusal for short-term transmission service requests.

1424. To understand commenter concerns, it is useful to note the relevant components of the reservation and scheduling process in the *pro forma* OATT. Reservations for short-term firm point-to-point transmission service are available on a first-come, first-served basis and are conditional based upon the length of the requested transaction as explained further below. If the transmission system becomes oversubscribed, longer-term service may preempt shorter-term service, up to a specified period. The shorter-term reservation holder has a right of first refusal to match the longer-term reservation, but such right must be exercised within 24 hours of being notified of the competing reservation, or earlier to comply with the scheduling deadline.

Comments

1425. Salt River argues that the time required to administer the right of first refusal—which includes contacting customers and allowing time to exercise the right of first refusal—is overwhelming. Salt River argues that the current OASIS business practices do not permit adequate time to implement these rules, and the industry lacks the software to either streamline the effort or ensure quality control. Salt River contends that for hourly, daily, and weekly requests, the complexity and potentially unjust results of administering preemption and the right of first refusal rules outweighs any potential benefits. Accordingly, Salt River recommends revisions to the *pro forma* OATT that make the right of first refusal available only to monthly requests for service.

1426. To address the complications arising from preemption and the right of first refusal, Duke proposes several revisions to the *pro forma* OATT: only

[846] *See* NAESB Business Practice Standard 001–4.13.

[847] For instance, Idaho Power Company has adopted a business practice that requests for monthly firm transmission service cannot be submitted earlier than 11 months prior to operation. Portland General Electric has adopted a business practice that Daily Firm ATC on the California-Oregon Intertie will be posted at or about 7:11 a.m. Pacific on the day prior to operation and that requests that are submitted prior to ATC being posted will be refused. SPP has modified its tariff so that requests for monthly firm transmission service cannot be submitted more than 90 days prior to the first day of operation.

pre-confirmed requests would trigger preemption; confirmed requests could not be displaced by longer-term requests; only monthly customers subject to preemption would be given a right of first refusal (Salt River proposes a similar OATT revision); and, profiled requests (*i.e.*, requests for transmission that may have different MW values for each hour of the day, and may even include some hours where the MW value is zero) would not be granted priority over confirmed reservations. TranServ also asks the Commission to provide guidance establishing the earliest and latest submission times and maximum successive or consecutive terms of service required. TranServ contends it is unreasonable that a request for daily firm service could be submitted years in advance and then have a right of first refusal to match any longer-term request for service.

1427. To eliminate the potential for more complexity, TranServ requests that the Commission eliminate the conditional nature of short-term point-to-point service under the OATT. Whether the Commission adopts this recommendation, TranServ further recommends that the Commission revise the timing provisions for requesting short-term point-to-point service to reduce overlap for submission of requests that would trigger the need for preemption. TranServ and Duke recommend a reservation or bidding process in which one increment of service (monthly, weekly, daily, and hourly) is available at a time, with each successive shorter increment of service becoming available after the reservation or bidding window for the preceding longer increment has closed.

1428. NorthWestern requests that the Commission clarify whether the terms ''reservation'' and ''request'' used in section 13.2 (Reservation Priority) are used interchangeably. If they are not used interchangeably, and ''reservation'' is meant to be a confirmed request, while ''request'' is a queued request that has not been confirmed, NorthWestern suggests that the sentence that includes the two uses of ''reservation'' creates confusion because, if both requests are confirmed, then either sufficient capacity exists to accept both requests, or the transmission provider accepted requests that exceed the ATC. To avoid confusion, then NorthWestern recommends that the second use of ''reservation'' should be changed to ''request.'' If so, to avoid the suggestion that the section is attempting to distinguish between requests that have been confirmed from those simply queued, NorthWestern recommends that the Commission consider changing all of the ''reservation'' references to ''request.''

Commission Determination

1429. Based on the issues raised in comments, we find that changing the ''first come, first served'' nature of the reservation process and right of first refusal process is not warranted at this time. The ''first-come, first-served'' principle facilitates the administration of the reservation process and benefits customers because there can be little confusion about how to comply with it.

1430. The remaining concerns regarding administering the right of first refusal are addressed below. First, when a longer-term request seeks capacity allocated to multiple shorter-term requests, the shorter-term customers should have simultaneous opportunities to exercise the right of first refusal. Duration, pre-confirmation status, price, and time of response would then be used to determine which of the shorter-term requests will be able to exercise the right of first refusal, consistent with the Commission's tie breaking provision in section 13.2(ii). Second, to minimize the potential for gaming, a preempting longer request must be for a fixed capacity over the term of the request.

1431. We agree with NorthWestern's assertion that the sentence in section 13.2(iii) of the *pro forma* OATT that includes the two uses of ''reservation'' creates confusion. Therefore, we clarify that the terms ''reservation'' and ''request'' are not used interchangeably; ''reservation'' is meant to be a confirmed request, while ''request'' is a queued request that has not been confirmed. To clarify the distinction between use of the terms ''request'' and ''reservation'' in section 13.2(iii), we will revise that section so that the sentence ''Before the conditional reservation deadline, if available transfer capability is insufficient to satisfy all Applications, an Eligible Customer with a reservation for shorter-term service has the right of first refusal to match any longer-term *reservation* before losing its reservation priority'' is replaced by the sentence ''Before the conditional reservation deadline, if available transfer capability is insufficient to satisfy all Applications, an Eligible Customer with a reservation for shorter-term service has the right of first refusal to match any longer-term *request* before losing its reservation priority.''

6. Designation of Network Resources

a. Qualification as a Network Resource

1432. Taken together, the following sections of the *pro forma* OATT describe the resources a network customer can appropriately designate as a network resource. Section 30.1 of the *pro forma* OATT describes network resources as all generation owned or purchased by the network customer designated to serve network load under the tariff. Section 30.1 also indicates that network resources may not include resources that are committed for sale to non-designated third-party load or otherwise cannot be called upon to meet the network customer's network load on a noninterruptible basis. Pursuant to section 30.7 of the *pro forma* OATT, the network customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a network resource. Alternatively, the network customer may establish that execution of a contract is contingent upon the availability of network service. Section 29.2 requires the network customer to provide the following information about a power purchase agreement that is to serve as a new designated network resource: source of supply, control area location, transmission arrangements and delivery point(s) to the transmission provider's transmission system.

1433. As the Commission noted in the NOPR, a number of orders address what types of resources meet the criteria set out in sections 30.1 and 30.7 of the *pro forma* OATT. In *MSCG*, the Commission stated that network resources must be generating resources owned by the network customer or purchases of noninterruptible power under executed contracts that require the network customer to pay for the purchase.[848] In *WPPI*, the Commission found that a network customer can designate as a network resource a system purchase that is not backed by a specific generator.[849] The Commission found that Wisconsin Public Service Corporation (WPS) had appropriately designated a power purchase as a network resource, even though the power purchase agreement did not require WPS to take energy around the clock and allowed WPS to convert its energy purchase to a discounted product that could be interrupted.[850] In addition, the Commission stated that, because the *pro forma* OATT requires a power purchase to be noninterruptible, third-party transmission arrangements to deliver the resource to the network have to be

[848] *Morgan Stanley Capital Group* v. *Illinois Power Co.*, 83 FERC ¶ 61,204 at 61,911–12 (1998), *order on reh'g*, 93 FERC ¶ 61,081 (2000) (*MSCG*).

[849] *Wisconsin Public Power Inc.* v. *Wisconsin Public Service Corp.*, 84 FERC ¶ 61,120 at 61,650–51 (1998) (*WPPI*).

[850] *Id.*

noninterruptible as well.[851] In *Illinois Power*, the Commission found that a firm purchase need not be backed by a capacity purchase to qualify as a network resource.[852]

NOPR Proposal

1434. In the NOPR, the Commission proposed to maintain its current policy regarding the power purchase agreements that network customers may designate as network resources. In particular, the Commission proposed that a network customer would continue to be able to designate resources from system purchases not linked to a specific generating unit, provided the power purchase agreement is not interruptible for economic reasons, does not allow the seller to fail to perform under the contract for economic reasons, and requires the network customer to pay for the purchase. In addition, the Commission reiterated that third-party transmission arrangements to deliver the purchase to the network must be noninterruptible.

1435. Regarding seller's choice contracts, the Commission explained that a power purchase agreement that is structured so that a network customer cannot specify all of the information required by section 29.2(v) of the *pro forma* OATT cannot be designated as a network resource. Specifically, the Commission reiterated that a request to designate a new network resource must provide the information including the source of supply, control area location, transmission arrangements, and delivery point(s) to the transmission provider's transmission system. The Commission proposed that, when designating a system purchase as a new network resource, a network customer must identify the resource as a system purchase as well as the control area from which the power will originate.

1436. In response to suggestions that liquidated damages (LD) products should not be designated network resources because they are interruptible for economic reasons, the Commission proposed to clarify that network customers may not designate as network resources those power purchase agreements that give the seller a contractual right to compensate the buyer instead of delivering power even if the seller is able to deliver power. For instance, the Commission proposed that a network customer may not designate as a network resource a purchase agreement that allows the seller to interrupt sales under the purchase agreement for reasons other than reliability, but allows the buyer to force delivery at a higher price. In addition, the Commission proposed that a network customer may not designate as a network resource a purchase agreement that requires a seller to pay the buyer's cost of replacement power when the seller chooses not to deliver energy for economic reasons.

Comments Overview

1437. Most commenters argue that the Commission must provide further clarification than given in the NOPR, particularly with regard to the eligibility of firm LD power products and the information required by section 29.2(v) of the *pro forma* OATT for seller's choice contracts. Various commenters also argue that the Commission's precedent on this issue is contradictory and that the Commission's policy with respect to designation of network resources may violate section 217 of the FPA and conflict with state jurisdiction.

(1) LD Contracts

Comments

1438. Many commenters express general support for some or all of the Commission's clarifications in the NOPR with regard to ineligibility of resources which are interruptible for economic reasons and/or that allow the seller to compensate the buyer instead of delivering power even if the seller is able to deliver power.[853] However, many commenters express concern about the clarity of the policy.[854]

1439. In particular, several parties contend that it is in fact the firmness of the contract and not the mere existence of an LD provision describing the remedies in case of a failure to perform that determines the eligibility of a power purchase agreement to be designated as a network resource.[855] TAPS argues that, in order to determine the firmness of a purchase, one must look at the criteria for excusing a failure to supply. AMP-Ohio, MISO, and NCPA also express support for this position, pointing to the Commission's finding in *Dynegy*[856] that the inclusion of an LD provision in EEI's Master Power Purchase and Sale Agreement's Firm LD product (EEI's Firm LD Product) does not inherently make that product less firm.

1440. Several commenters argue that, when the Commission in *Dynegy* considered the acceptability of EEI's Firm LD Product as a designated network resource, it neglected to consider the presence of a provision which appears to contradict its decision.[857] They point to the Commission's statement in *Dynegy* that EEI's Firm LD Product ''does not permit the power to be interrupted for economic reasons, or at the discretion of either party, but only if a force majeure occurs.''[858] Some contend that the Commission's conclusion ignored the fact that EEI's Firm LD Product actually allows power to be interrupted for *any* reason, including economic reasons, after which the agreement then provides LDs as a remedy if the interruption was not due to a force majeure event.[859] Duke and EEI note that contracts under EEI's Firm LD Product agreement or similar agreements have become commonplace since the Commission's *Dynegy* decision and that clarification regarding their use as network resources is required to address industry confusion.

1441. Several commenters disagree that the EEI Firm LD Product gives parties the right to interrupt for any reason, including economic reasons, provided that LDs are paid by the non-performing party.[860] Hoosier argues on reply that EEI and Southern have misunderstood the Commission's intent in *Dynegy*. Hoosier contends that the Commission correctly found in *Dynegy* that the EEI Firm LD Product does not permit power to be interrupted for economic reasons, or at the discretion of either party, but only if a force majeure event occurs. Thus, Hoosier argues, the EEI Firm LD Product does not give the seller a *right* to interrupt for any reason other than force majeure, and any seller that interrupts for economic reasons is clearly in breach of its obligations to perform under the contract and must

[851] *Id.* at 61,660.

[852] *Illinois Power Co.*, 102 FERC ¶ 61,257 at P 14 (2003), *reh'g denied*, 108 FERC ¶ 61,175 (2004) (*Illinois Power*).

[853] *E.g.,* Ameren, BART, Constellation, Duke, Entegra, Entergy, Morgan Stanley, MISO, NorthWestern, Progress Energy, Sempra Global, Southern, Suez Energy NA, and TranServ.

[854] *E.g.,* AMP-Ohio, APPA, Duke, EEI, Entergy, Fayetteville, Morgan Stanley, NCPA, Northwest IOUs, Northwest Parties, MISO/PJM States, PGP, Pinnacle, PNM–TNMP, Salt River, Sempra Global, Southern, TAPS, Utah Municipals, and WSPP.

[855] *E.g.,* AMP-Ohio, Northwest IOUs, NRECA Reply, PGP, Pinnacle, Sempra Global, Strategic Energy Reply, and TAPS.

[856] *Dynegy Midwest Generation*, 101 FERC ¶ 61,295 (2002), *reh'g dismissed*, 108 FERC ¶ 61,175 (2004) (*Dynegy*).

[857] *E.g.,* Duke, Dynegy Reply, EEI, and Southern.

[858] *Dynegy* at P 21.

[859] *E.g.,* Duke, EEI and Southern. EEI notes that its Firm LD Product is distinct from its ''System Firm'' and ''Unit Firm'' products in its Master Power Purchase and Sale Agreement, each of which excuses a failure to perform only for force majeure and neither of which permits a party to fail to perform and pay liquidated damages.

[860] *E.g.,* Hoosier Reply, Strategic Energy Reply, and Utah Municipals.

pay damages. Hoosier acknowledges that a seller always has the choice of not performing its obligations and paying damages, but that is not peculiar to the EEI Firm LD Product. Hoosier maintains that any party to any contract has the *ability*, but not the *right*, to breach its obligations under the contract and pay damages. According to Hoosier, the only difference in the case of the EEI Firm LD Product is that the parties have stipulated beforehand as to the measure of the damages required of a seller in breach, in order to minimize litigation over damages. This stipulation, Hoosier argues, conveys no additional substantive rights on either party.

1442. Several parties note that firm LD contracts account for a significant number of currently utilized products and that disallowing these product to be designated as network resources may create significant disruption.[861] Commenters supporting continued use of firm LD contracts as designated network resources argue that allowing products structured on EEI's Firm LD Product has not created reliability problems.[862] Southern argues that the Commission should not set criteria that would place in jeopardy an array of products that have a firm LD dimension. Southern further states that such products are among the most reliable in instances where market prices are very high (where LDs could be quite substantial) and that just about any power purchase/sale contract can be financially settled in real-time or for a given period in lieu of physical delivery during that period. The fact that some contracts set out in advance the terms of such settlement (so to render commerce more efficient and liquid) does not, Southern argues, render those contracts any less qualified for designation as network resources. Thus, Southern encourages the Commission to reconsider its revised guidance regarding the ineligibility of contracts structured after EEI's Firm LD Product. Utah Municipals agrees, and similarly requests that contracts under EEI's Firm LD Product be allowed to qualify as network resources.

1443. Morgan Stanley argues that the notion that firm LD contracts do not contribute as much to resource adequacy as contracts tied to individual physical resources is inaccurate. Morgan Stanley contends that the incentive to ensure performance is far greater with a firm LD obligation than with unit contingent and system firm contracts. Morgan Stanley explains that unit contingent and system firm contracts require delivery if the unit or group of units performs and excuses delivery if they do not, while a Firm LD obligation requires delivery so long as it is physically possible to achieve delivery, regardless of the cost of doing so. Thus, according to Morgan Stanley, firm LD products can enhance supply security because they are not dependent upon the performance of an individual unit or units, but rather put the burden and opportunity on the supplier to use multiple physical resources to meet its obligations.

1444. APPA also requests reconsideration of this issue, arguing that its members are often presented with power purchase agreements based on EEI's Firm LD Product and that they are not always successful in negotiating amendments to such agreements with suppliers. APPA argues that an LSE can use a diverse resource portfolio, including firm LD power purchase agreements, to serve its load economically, while meeting reliability requirements and advancing other important policy objectives (diverse fuel mix, use of renewable energy, *etc.*). APPA urges the Commission to allow such use if it is consistent with the commercial practices in a region.[863]

1445. NCPA also opposes forbidding firm LD products without looking more fully into their merits and the potential safeguards that could be built into them. NCPA recognizes that firm LD contracts raise certain issues under the *pro forma* OATT and also pose issues for planning where a specific resource is not designated, but these problems are not significantly different from the problems of a large transmission owner designating its entire fleet as network resources for its entire load. Rather than ban LD contracts from an important segment of the market, several commenters suggest that the Commission convene a separate proceeding or conference to further investigate the issue.[864]

1446. Other commenters argue against allowing the designation as network resources of contracts that permit the interruption of power sales for reasons other than reliability as long as LDs are paid.[865] Detroit Edison argues in its reply comments that a seller's decision to pay the ''costs of 'cover' '' under these contracts is of no value to an LSE that lacks deliverable alternatives. Detroit Edison further claims that, contrary to Southern's assumption that a failure to deliver under a firm LD contract would result in substantial non-delivery penalties, one would expect a supplier afforded the option to divert power to a higher priced market that produces a net financial gain would elect to interrupt service under the power sales contract and pay the LDs. Detroit Edison contends that purchasers would be left hanging during periods of supply shortage when firm physical supply is most critical.

1447. In its reply comments, Duke asserts that allowing firm LD products to be designated as network resources would result in network customers leaning on its system. Although it has doubts about whether the EEI Firm LD Product actually contains language that prohibits interruptions for economic reasons, Duke would find the inclusion of such language in purchased power agreements to provide sufficient firmness to allow the contract to be designated as a network resource. In its reply comments, Dynegy argues that allowing designation of firm LD products is simply inconsistent with the existing OATT requirements that a transmission customer either own, purchase or have rights to generation.

1448. Northwest IOUs request that the Commission clarify whether the limitations for qualification of a network resource, such as the presence or absence of an LD clause, would prevent a transmission provider from using such a resource for service to its bundled native load customers. Northwest IOUs state that, if the non-rate terms and conditions do not apply directly by requirement of the Final Rule, but only under a comparability test where there is a comparison to network customers, then that position should be made clear. They further note that some transmission providers have no comparable network service, or no service involving generating units within the transmission provider's control area. Accordingly, Northwest IOUs request that the Commission clarify whether, in those instances, the limitations for qualification of a network resource would apply.

1449. Many commenters also argue for the eligibility of service provided under the WSPP Service Schedule C (Schedule C) agreement.[866] In particular, WSPP argues that its Schedule C product satisfies the Commission's requirements for designation as a network resource because it requires the seller to deliver power except under very limited

[861] *E.g.,* APPA, Hoosier Reply, NCPA, Southern, Strategic Energy Reply, and Utah Municipals.

[862] *E.g.,* EEI, Hoosier Reply, Southern and NCPA.

[863] MISO/PJM States similarly argue that whether a particular contract with LD provisions can serve as a designated resource should be decided within the RTO stakeholder process.

[864] *E.g.,* APPA Reply, Morgan Stanley, and NCPA.

[865] *E.g.,* Duke, Dynegy, and Detroit Edison Reply.

[866] *E.g.,* APPA, EEI, Entergy, Northwest Parties, Salt River, Utah Municipals, and WSPP.

circumstances, such as force majeure, and that the agreement itself clearly provides that it is a firm product. However, WSPP notes that its product, like most if not all wholesale power sales contracts, contains a damages provision which could be characterized as an LD provision. WSPP contends that such provision is used simply to avoid the need to litigate damages and not to permit a seller to ignore its delivery obligations by financially settling a firm power sale. WSPP states that it is not intended that sellers be allowed to refuse to deliver for economic reasons. Therefore, WSPP requests clarification that its Schedule C product is eligible for designation as a network resource, and notes the potential for significant disruptions in the market and WSPP member sales of firm products if its Schedule C product is not considered eligible for designation as a network resource.

1450. EEI and Northwest Parties note that, in some instances, both the sellers and buyers of the Schedule C product designate that product as a network resource, since it appears to meet the *pro forma* OATT definition of a network resource for both parties because the agreement allows interruptions to serve native loads. If only one party is found to be able to designate the Schedule C product as a network resource, EEI argues that the other party would run the risk of civil penalties for making an incorrect attestation and may also lose the transmission rights that it needs to serve its native load or network load. Northwest Parties request specific clarification as to whether power purchased under Schedule C from a seller with public utility or statutory obligations to its customers is to be considered power available to meet the purchaser's network load on a non-interruptible basis, given that the seller may interrupt service under the power sales contract to meet its public utility or statutory obligations. If the Commission decides that the Schedule C transactions cannot be designated as network resources, Northwest Parties asks the Commission to state whether such transactions would be eligible if the WSPP service agreement requires the seller to give the purchaser advance notice of an interruption. Salt River also asks that, if Schedule C is found to be ineligible, the Commission identify the specific changes needed to that contract to allow for designation.

1451. Beyond the eligibility of contracts with LDs to be designated as network resources, EEI and Duke also argue that there is a conflict between the policy guidance given in *Dynegy* (that a power purchase agreement which is interruptible for reasons other than reliability is not eligible for designation as a network resource) and the guidance given in *WPPI* [867] (that a power purchase agreement which permits curtailment to serve the seller's native load is eligible for designation as a network resource). Duke argues that, since the type of contracts contemplated in *WPPI* are clearly interruptible for reasons other than reliability, *WPPI* should no longer be deemed valid case law in light of the Commission's proposed clarifications in the NOPR. Duke argues that allowing such contracts to be designated as network resources creates reliability risks and likely permits two entities to designate the same generation as network resources. While Duke acknowledges that exceptions to this rule may be necessary in the Western Interconnection, it does not support an exception for the Eastern Interconnection. EEI argues that the conflict between the *Dynegy* and *WPPI* standards has resulted in different transmission providers and customers using different standards for designation of network resources. EEI therefore asks the Commission to clarify precisely what contracts qualify as a network resource before it implements its proposed attestation requirement.

Commission Determination

1452. Many commenters seek clarification of the eligibility of power purchase agreements with LD provision to be designated as network resources. In clarifying our policy concerning firm LD products, we turn first to the apparent confusion surrounding the Commission's findings in *Dynegy*. Duke, *Dynegy*, EEI, and Southern argue that the Commission incorrectly found in *Dynegy* that the EEI Firm LD Product could not be interrupted for economic reasons. These parties argue that the EEI Firm LD product actually allows power to be interrupted for *any* reason, including economic reasons, after which LDs are assessed if the interruption was not due to a force majeure event. We disagree. As Hoosier points out, the EEI Firm LD Product does not permit power to be interrupted for economic reasons. While any party to any contract can choose to fail to perform, that does not convey a contractual right to fail to perform. The EEI contract clearly obligates the supplier to provide power, except in cases of force majeure. Thus, the contract does not *allow* interruption for economic reasons. The presence of an LD provision in the EEI Firm LD Product does not permit the seller to violate the terms of the contract, but rather merely specifies the damages that must be paid if the seller fails to perform under the contract. As noted by many commenters, it is the firmness of a power purchase contract, and not simply the presence or absence of an LD provision, that determines the eligibility of that power purchase to be designated as a network resource.

1453. We conclude, however, that the firmness of an obligation to provide under a contract with an LD provision is informed by the particular terms of the LD provision. The type of LD provision commonly seen in firm LD products, such as the EEI Firm LD Product, obligates the supplier, in the case of interruption for reasons other than force majeure, to make the aggrieved buyer financially whole by reimbursing them for the additional costs, if any, of replacement power. In contrast to this ''make whole'' type of LD provision, other types of LD provisions establish penalties at a fixed-dollar amount, cap penalties at some level, or are otherwise not equivalent to a general ''make whole'' type provision. Under these other types of LD provisions, suppliers only need to compare their savings from interrupting with the specified LD penalty when deciding whether to interrupt power sales. Because such a consideration may not take into account the cost of replacement power, such LD provisions could lead to inefficient supplier interruption and economic harm to the buyer.

1454. We find that a ''make whole'' LD provision, such as that found in the EEI Firm LD Product and in the WSPP Schedule C agreement, does not create incentives that are incompatible with the firmness of the overall product. ''Make whole'' LDs require the seller to consider the price of the replacement power, if it is available, to its original buyer if the seller fails to perform under the contract. There could, of course, be situations where the supplier is still presented with a net financial gain and has an incentive to interrupt, but those incentives would seem to be the same incentives faced by a designated network resource that is a specific generating plant owned by the network customer. In such an instance, the network customer may determine, from time to time, that it is more economic to substitute power from an alternate source in order to allow the originally designated resource to either shut down or to sell its output into the wholesale market. We find no reason to create financial incentives that make purchased power designated as a

[867] *WPPI*, 84 FERC at 61,652.

network resource financially ''more firm'' than owned generation.

1455. Accordingly, we find that the inclusion of a ''make whole'' LD provision in a power purchase agreement does not disqualify that agreement from being designated as a network resource. However, other types of LD provisions may create incentives that are incompatible with the firmness of a power purchase agreement. Thus, as of the effective date of this Final Rule, power purchase agreements designated as network resources may only contain LD provisions that are of the ''make whole'' type. Conversely, power purchase agreements containing LD provisions that provide penalties of a fixed amount, that are capped at a fixed amount, or that otherwise do not require the seller to pay an aggrieved buyer the full cost of replacing interrupted power, are not acceptable. Any contract which contains an unacceptable LD provision, but otherwise qualifies for designation as a network resource and has been properly designated as a network resource prior to the effective date of this Final Rule, will be grandfathered only until the earlier of (1) the expiration of the current term of the power purchase agreement or (2) an indefinite termination [868] of the power purchase agreement as a designated network resource pursuant to section 30.3 of the *pro forma* OATT. In response to the many comments received, we confirm that the LD provisions in both the EEI Firm LD Product and the WSPP Schedule C agreement are acceptable.[869]

1456. Detroit Edison argues that a seller's obligation to pay the cost of replacement power under firm LD contracts is of no value to an LSE that lacks deliverable alternatives. Detroit Edison appears to assume that, as long as an LSE purchasing power had no deliverable alternatives from which to procure power, a designated supplier would not be liable for damages if it chose to interrupt power sales to the buyer for reasons other than force majeure. We disagree. Detroit Edison is addressing the fairly unusual circumstance where a power supply is interrupted, there are no available alternatives in the market, and firm load therefore must be interrupted. We fail to see why this circumstance, and the difficulty of calculating damages for lost load when it occurs, provides a reason why a particular network resource (an LD contract) should not qualify under the *pro forma* OATT as a network resource.

1457. We also disagree with Dynegy's argument that allowing the designation of firm LD products is inconsistent with the existing OATT requirement that a transmission customer own, purchase or have rights to generation. As discussed, firm LD contracts that meet the Commission's requirements for designation do create for the buyer a contractual right to generation and do not contain damage provisions which make the actual incentives under such contracts incompatible with those present in owned generation.

1458. In response to Northwest IOUs' request, we also clarify that the presence or absence of an LD provision does not prevent a transmission provider from using such a resource to serve its bundled native load customers. Rather, as we explain above, it is the type of LD provision that is controlling. A power purchase contract with a ''make whole'' remedy could be used to serve native load customers.

1459. We disagree with Duke and EEI's argument that there is a conflict between the policy guidance given in *Dynegy* (that a power purchase agreement which is interruptible for reasons other than reliability is not eligible for designation as a network resource) and the guidance given in *WPPI* (that a power purchase agreement which permits curtailment to serve the seller's native load is eligible for designation as a network resource). We reiterate the Commission's finding in *WPPI* that a power purchase agreement properly designated as a network resource may permit *curtailment* to serve the seller's native load. Consistent with the long-standing definition in Order No. 888, ''curtailment'' contemplates a reduction in service as a result of system reliability conditions, not economic reasons.

1460. Although we find that the LD provision contained in the WSPP Schedule C agreement does not impair the firmness of that agreement, we note that the agreement otherwise allows interruptions in generation service ''to meet [the] Seller's public utility or statutory obligations to its customers.'' Thus, the WSPP Schedule C agreement appears to allow interruptions for reasons other than reliability and, as a result, would not be eligible for designation as a network resource under the *Dynegy* or *WPPI* precedent. We find that the provision in the WSPP Schedule C agreement allowing for interruption of generation service in order to serve native load would need to be revised to explicitly prohibit interruptions for reasons other than reliability of service to native load in order for that provision to meet the requirements established under *Dynegy* and *WPPI*.

1461. Maintaining the standard for eligibility established in *Dynegy* and *WPPI* will further the Commission's goals of preventing undue discrimination, promoting comparable treatment of customers, and increasing the accuracy of ATC calculations. However, we acknowledge that some may currently be relying on the WSPP Schedule C agreement in designating network resources and that there may be disruption if we were to invalidate the designations of the existing WSPP Schedule C resources. Thus, we exercise our discretion not to invalidate existing designations of the WSPP Schedule C agreements as a result of noncompliance with this particular requirement until the earlier of the following: (1) The expiration of the current term of a power purchase agreement or (2) redesignation of a previously designated WSPP Schedule C resource following a period of temporary or indefinite termination pursuant to sections 30.2 and 30.3 of the *pro forma* OATT. Alternatively, parties may voluntarily reform the offending contract terms in order to preserve their eligibility for network service.

(2) Off-System Resources

Comments

1462. Many commenters request clarification or reconsideration of the information that is required to be specified in section 29.2(v) of the *pro forma* OATT in order to designate a seller's choice contract or system sale as a network resource. Northwest Parties agree with the proposal in the NOPR that system sales may be designated by providing the control area from which the sale is made, transmission arrangements, and delivery points to the transmission provider's transmission system.[870] For system sales, Northwest

[868] As discussed below, in section V.D.6.c, termination of network resource status may either be temporary or indefinite. A firm LD contract that does not have a ''make whole'' LD provision and which is grandfathered here may continue to be temporarily terminated in order to make third-party sales without jeopardizing its eligibility to be redesignated after a third-party sale. However, once a network resource is indefinitely terminated, it must comport with the requirements for LD provisions, and all other requirements for designation of network resources, before it can be redesignated.

[869] As discussed below, however, we otherwise find that the WSPP Schedule C agreement does not comply with the requirements for designation as a network resource because it allows for interruption for reasons other than reliability. We therefore do not need to address requests to clarify that both the buying and selling party to a WSPP Schedule C contract can designate network resources associated with the contract.

[870] Northwest Parties request similar clarification for designation of purchase contracts from one or more specified, individual resources.

Parties argue that unit-specific information is not needed because such sales are, by definition, from a variety of resources and, in any event, the resource-specific information is typically not available to the purchaser. This is particularly true, they argue, for sales from large hydroelectric systems, which are operated as one interconnected unit. For purchase contracts, they argue that unit-specific information is not needed because it is provided in the generation interconnection agreement to the control area where the resource is located. Northwest Parties contend that not requiring unit-specific information for purchase of power, including purchases of system power, is consistent with the Commission's description in the NOPR of the requirements to designate a network resource.

1463. Pinnacle argues that the Final Rule should recognize that the level of detail required by section 29.2(v) may vary depending on circumstances and permit the transmission provider to determine the level of information necessary for the evaluation of the network resource. In some cases, a power purchase agreement may, they argue, appropriately refer to more general information than a specific single control area or single source of supply.

1464. In cases where a power purchase agreement is being sourced by generating units from an external control area, Entergy contends on reply that simply identifying the control area is sufficient for purposes of studying the deliverability of that resource. However, in cases where the power is sourced by generating units internal to the transmission provider's control area, Entergy argues that identifying only the control area does not provide sufficient information to study deliverability. In that case, Entergy argues that the customer must provide the specific information required by section 29.2(v) of the *pro forma* OATT, including the location of the specific generating units. If such information is not available at the time of the network resource designation, Entergy argues that the customer should still be able to designate the agreement as a network resource, but that the customer would have to confirm resource deliverability prior to actually scheduling the service.

1465. TDU Systems argue in their reply comments that specifying the control area and the interface over which power will enter the transmission provider's transmission system from a designated network resource in an external control area is sufficient for purposes of studying the deliverability of that resource. TDU Systems also argue that, for competitive reasons, an LSE should never be required to identify the generator or the transmission zone where the generator is located.

1466. In contrast, EEI requests that the Commission modify section 29.2(v) to clearly state that the transmission provider has the discretion to require the network customer to identify the location of the generator with more specificity than simply specifying the control area in which the network resource is located, since the location will affect the flowgate over which the energy will be transmitted. EEI argues that it is necessary to narrow the location of the source of a power purchase to the system of a particular transmission owner, rather than a control area. PNM-TNMP and Duke also support requirements that network customers provide more information concerning the location of off-system network resources and purchase agreements so that the transmission provider can properly evaluate the impact on its system. Duke states that Duke Carolinas are now receiving requests to designate as network resources power purchase agreements that list the point of delivery as ''the PJM control area'' or ''into Southern.''

1467. Dynegy argues in its reply comments that the Commission has never explained how a transmission customer designating a firm LD contract as a network resource could ever comply with section 29.2 of the *pro forma* OATT, which requires specific information about the generation resource being designated. Dynegy contends that, just like a seller's choice contract, a customer is not entitled to any information about particular generating assets when entering a firm LD purchase contract such as the EEI Firm LD Product. As a result, Dynegy states that it is unclear how a network customer would ever be able to legitimately designate such contracts as a network resource.

1468. In order to help ensure that all network resources are in fact backed by capacity, Dynegy argues that the Commission should require identification of more than just the control area when designating a network resource. Dynegy argues that the Commission should require the generation owner or trading agent for the generation to positively verify that capacity was sold to the entity designating that particular generator as a network resource, and that the designation is appropriate pursuant to the parties' agreement, as is currently required in PJM.

1469. Because some regions of the country determine ATC using a flow-based methodology and other regions use a rated path methodology, EEI argues that section 29.2(v) should be modified to permit transmission providers to require a network customer to designate the point to which the energy is delivered and from which the transmission provider will provide network service if it is not delivered at the generator bus.

1470. Duke requests that the Commission resolve an inconsistency between the NOPR's statement at P 408 that ''when a network customer is designating a system purchase as a new network resource, the source information required in section 29.2(v) should identify that the resource is a system purchase and should identify the control area from which the power will originate,'' and the statement in the very next sentence that a ''power purchase agreement that is structured so that a network customer cannot specify all of the information required by section 29.2(v) cannot be designated as a network resource.'' Duke notes that significantly more information is required by section 29.2(v) (unit size, VAR capability, operating restrictions, variable generating cost for redispatch computations, *etc.*) than the ''control area from which the power will originate.''

1471. Morgan Stanley contends that the information required in section 29.2(v) must not disallow designation of seller's choice contracts as network resources. They assert that transmission providers use security constrained economic dispatch under which the source of supply in a contract is generally irrelevant from a planning or operational perspective and is therefore not needed. Morgan Stanley also argues that, if the underlying network customer's contract permits the seller to curtail its dispatch and substitute a source from the market, the transmission provider would never actually know the location where a network customer's power is coming from and, thus, it is unclear why the specification of that source should be a requirement. Therefore, Morgan Stanley requests that the Commission consider revising 29.2(v) to eliminate the inclusion of information that is not necessary or make the provision of such information required ''to the extent practicable.''

1472. Duke replies that Morgan Stanley accurately portrays what typically happens under seller's choice contracts, but reaches the wrong conclusion about a remedy. Duke argues that, if network customers are permitted

to designate as network resources contracts that may be relatively long-term, but under which the seller has no obligation to identify the source of the power any sooner than on a day-ahead basis, then ATC may be reserved even though there is no intent to use it. Duke also argues that allowing seller's choice contracts would hamper the transmission provider's ability to plan its system. In Duke's view, it would be appropriate to permit a seller's choice contract to be a designated network resource at the time transmission service is granted for the period such transmission service lasts, as at that point the customer will have designated a source and sink.

1473. Fayetteville recognizes that there are problems related to modeling and reliability in contracts for energy which do not specify particular units as sources, but argues that these problems are exactly the same as those that exist within any vertically integrated utility which names its generation fleet as network resources for its native load.

Commission Determination

1474. Many comments were received with respect to seller's choice and system purchases. Some comments refer not only to seller's choice and system purchases, but also to other possible off-system transactions, including sourcing from owned generation located off-system. We therefore use the term ''off-system resources'' here to refer to all such resources.

1475. The existing requirements in section 29.2(v) are intended to ensure that the network customer designating resources on other transmission systems provides sufficient information to allow the local transmission provider to determine the effect on ATC. Conversely, network customers should not be permitted to designate off-system resources which are so vaguely defined that the effects on ATC cannot be determined. In light of the requests that the Commission clarify exactly what information must be provided in order to designate network resources located off-system, and what information required by section 29.2(v) must be posted on OASIS, we will revise section 29.2(v) of the *pro forma* OATT to specify exactly what information is required.

1476. As revised by the Final Rule, section 29.2(v) of the *pro forma* OATT will require the following information to be provided with the request and posted on OASIS when designating an off-system resource: (1) Identification of the resource as an off-system resource; (2) amount of power to which the customer has rights; (3) identification of the control area(s) from which the power will originate; (4) delivery point(s) to the transmission provider's transmission system; and (5) transmission arrangements on the external transmission system(s). Additionally, section 29.2(v) is revised to require that the following information be provided with such designation, but such information must be masked on OASIS to prevent the release of commercially sensitive information including (1) any operating restrictions (periods of restricted operation, maintenance schedules, minimum loading level of resource, normal operating level of resource); and, (2) approximate variable generating cost ($/MWH) for redispatch computations. Requests to designate off-system network resources submitted on or after the effective date of this Final Rule must include all of the information listed above.

1477. We direct transmission providers to develop OASIS functionality to (1) allow all of the information required for a request to designate network resources to be provided electronically, (2) mask information about operating restrictions and generating cost on OASIS, and (3) allow for queries of all information provided with designation requests in accordance with section 37.6 of the Commission's regulations.[871] As provided in paragraph 385, we also direct transmission providers to work in conjunction with NAESB to develop business practice standards describing procedural requirements for submitting designations over any new OASIS functionality. Transmission providers need not implement this new OASIS functionality and any related business practices until NAESB develops appropriate standards. Prior to implementation of this new OASIS functionality, any information that cannot be provided electronically may be submitted by transmitting the information to the transmission provider by telefax or providing the information by telephone over the transmission provider's time recorded telephone line.

1478. Duke argues that there is an inconsistency between the following statements in P 408 of the NOPR: (1) ''when a network customer is designating a system purchase as a new network resource, the source information required in section 29.2(v) should identify that the resource is a system purchase and should identify the control area from which the power will originate''; and (2) the statement in the very next sentence that a ''power purchase agreement that is structured so that a network customer cannot specify all of the information required by section 29.2(v) cannot be designated as a network resource.'' We disagree. The first statement only provided guidance on what could be provided in lieu of the *source of supply* information (as required in the last bullet of section 29.2(v) of the existing *pro forma* OATT) and was not intended to excuse customers from providing all of the relevant information for an off-system purchase other than the specific source of supply. However, the revisions to section 29.2(v) we adopt in this Final Rule remove any confusion.

1479. We disagree with Dynegy's argument that no firm LD contracts would be able to meet the requirements for designation. We note that all of the information required for off-system resources should be available for a seller's choice contract. Even firm LD contracts have variable generating costs (energy cost) and may have maintenance and other operating constraints. If no such constraints are contractually specified, or if no such constraints are relevant to an owned generation resource being designated, then that should be reflected in the information posted on OASIS.

1480. We reject Dynegy's request that the Commission require additional verification by sellers that capacity was in fact sold to an entity designating that particular generator as a network resource and that the network resource designation is appropriate pursuant to the parties' agreement. As the Commission explained in *Illinois Power*,[872] a firm energy purchase need not be backed by capacity to qualify as a designated network resource.

1481. We disagree with commenters who argue that more specific information than the control area must be provided with each request to designate system purchases or seller's choice contracts as network resources. In particular, we disagree with EEI's and Duke's argument that customers designating seller's choice contracts as network resources must be required, on a generic basis, to identify the specific transmission system, rather than the more general control area, in which the physical resources are located. EEI argues that such specificity is required for transmission providers to identify the individual flowgates over which the power will flow into their system. The existing section 29.2(v) of the *pro forma* OATT requires that customers designating network resources identify

[871] 18 CFR 37.6.

[872] 102 FERC ¶ 61,257 at P 14.

the ''delivery point(s) to the transmission provider's transmission system.'' We agree with Entergy and TDU Systems that providing both the control area in which off-system resources are located as well as the delivery point(s) to the transmission provider's transmission system is usually sufficiently specific to allow a transaction to be evaluated for its effect on the ATC of the local transmission system. However, we acknowledge Duke's concern about receiving requests to designate as network resources purchase agreements that list the point of delivery as only vague statements such as ''the PJM control area'' or ''into Southern.'' If any transmission provider believes that it faces unique circumstances that require deviations from the *pro forma* OATT in order to allow them to determine the effects of designations of network resources on ATC, it can, in a filing pursuant to FPA section 205, propose terms and conditions that it demonstrates are consistent with or superior to the *pro forma* OATT.

1482. Because some regions of the country determine ATC using a flow-based methodology and other regions use a rated path methodology, EEI argues that section 29.2(v) should be modified to permit transmission providers to require a network customer to designate the point to which the energy is delivered and from which the transmission provider will provide network service if it is not delivered at the generator bus. It is unclear what specific changes EEI is requesting. We note that, with respect to off-system purchases, section 29.2(v) of the *pro forma* OATT already requires that the delivery point(s) to the transmission provider's transmission system be included in the description of the network resource.

1483. In response to Entergy's request, we clarify that a customer may not designate as a network resource a seller's choice power purchase agreement which is sourced by generating units internal to the transmission provider's control area, since evaluating the effect on ATC would be problematic. We disagree with Entergy that a customer should be able to designate such a resource, even without specifying the location of the specific generating units, provided that the customer's network service from those units is contingent upon confirming resource deliverability prior to actually scheduling the service, because such a policy would still significantly obscure the evaluation of ATC. If a customer wishes to have a choice of resources that are internal to the particular transmission provider's control area from which to dispatch power, it must designate each of the resources as network resources.

1484. We disagree with Morgan Stanley's unsupported comments that the source of supply in a contract is irrelevant. We find that location of resources is a critical factor to the transmission provider's ATC calculations and its ability to model and evaluate the proposed network resource, regardless of whether the transmission providers use security constrained economic dispatch.

(3) Ability To Serve Native Load

Comments

1485. Many parties contend that the Commission's policy with regard to the qualification of network resources affects their ability to serve native load. EEI argues that energy purchases are an integral part of the resources many utilities use to serve their loads, yet often such projected energy purchases are not under contract until shortly before the power is needed. According to EEI, the requirement that a purchase contract be executed to qualify as a network resource jeopardizes the ability of such utilities to serve their native loads because they will not be able to reserve transmission capacity and other users may receive all of the ATC before their contracts are executed.

1486. APPA, EEI and Nevada Companies argue that restrictions on the types of generation and power supply arrangements that qualify for network service may violate section 217 of the FPA. EEI notes that section 217 provides that LSEs are entitled to use firm transmission rights to deliver the output of their generators or purchased energy to meet their service obligations to their loads. In EEI's view, section 217 requires the Commission to exercise its authority in a manner that enables LSEs to secure firm transmission rights on a long term basis for long term power supply arrangements made, or 'planned,' to meet such needs and, therefore, a requirement that network customers and transmission providers not reserve transmission capacity to serve their network loads and native loads unless they either own generation or have executed contracts that specify the source of the energy is inconsistent with section 217. APPA notes that section 217 does not distinguish among the types of power supply arrangements that an LSE must enter into to be protected and that section 217(b)(1)(A) refers to a broad universe of owned or contracted generation that would suffice, so long as the power supplies are for the purpose of meeting a service obligation.

1487. Newmont Mining disagrees that the Commission's requirements for designation of network resources are contrary to the new FPA section 217(b)(2). Newmont Mining argues the legislative history of section 217(b)(2) shows that it was intended essentially to codify Order No. 888 [873] and that the resource designation requirements do not deny LSEs any right to use their transmission, but rather prescribe how they are to implement that right.

1488. EEI, Nevada Companies, PNM-TNMP and South Carolina E&G on reply also argue that the Commission's requirements for eligibility for designation as a network resource may impermissibly conflict with state-mandated procurement plans. EEI and South Carolina E&G contend that, by imposing restrictions on the ability of LSEs to serve their native load, the Commission is indirectly asserting jurisdiction over state-regulated procurement practices, which they further argue is prohibited under *Northern States Power Co.* v. *FERC*.[874]

1489. Nevada Companies argue that the type of contracts that the Commission has determined to be eligible for qualification as network resources tend to be the most expensive. They point out that state regulatory agencies might determine that other types of contracts are more cost-effective without unnecessarily jeopardizing reliability. Even more troubling, they argue, is the problem created when transmission providers have peak loads that can more effectively be served by purchasing power on a short-term period (*i.e.*, less than one year). To reserve the transmission required to serve a needle peak that can occur anytime within a four month period would require the purchase of thousands of megawatt hours of power that Nevada Power knows it will not need, resulting in a disallowance by the Public Utility Commission of Nevada, which approves all open positions, options and hedges for Nevada Power.

1490. Nevada Companies contend that the network designation process should not be changed on systems where the process works reasonably well,

[873] In its reply comments, Newmont Mining cites (through reference to its own NOI reply comments) the statement in H.R. Rep No. 108–65 at 171 (2003) that ''[t]his section is intended to be consistent with the Commission's Order No. 888,'' as well as the statement in S. Rep. No. 109–78 at 50 (2005) that section 217 ''does not affect the Commission's authority under sections 205 and 206 [of the FPA] to ensure that rates are just and reasonable and not unduly discriminatory or preferential.''

[874] 176 F.3d 1090, 1096 (8th Cir. 1999), *cert. denied*, 528 U.S. 1182 (2000).

particularly on systems where transmission providers are required to make significant purchases of power to meet their retail loads. Nevada Companies argue that the Commission should therefore give transmission providers the option of instituting a reservation-based contract demand service similar to that previously approved in *Florida Power*.[875]

1491. Newmont Mining replies that Nevada Companies proposal is not similar to the Florida Power proposal or other approved contract demand network service arrangements, as those services were offered at the request of a network customer; designed to deal with a particular circumstance of the network customer; and offered as an option to, not as a replacement for, standard network integration services. Utah Municipals in their reply comments agree that utilities should not be permitted to unilaterally impose a contract demand ''reservation based'' methodology on its network customers.

1492. Newmont Mining argues that Nevada Companies' request to maintain an open position for a portion of their resource portfolio, in accordance with their required resource planning process, does have some basis, but that Nevada Companies' proposal is not the right solution. If the Commission is inclined to provide some relief to Nevada Companies, Newmont Mining argues that such relief should come, if at all, only after an investigation of how similar problems are handled on other systems and that such relief should be limited. The limitations Newmont Mining suggests include, among other things, excusing Nevada Companies from the requirement, if at all, only to the extent that a specific open portfolio position is contained in a resource plan approved in accordance with applicable law; requiring that the reservation be posted on OASIS; not granting a reservation to Nevada Companies over a competing application for network service by a potential network customer that actually has a designated network resource; and permitting other network customers to hold similar open positions.

Commission Determination

1493. We generally disagree with arguments that the Commission's restrictions on the designation of network resources may violate section 217 of the FPA. Congress did not require that LSEs be able to take transmission service without limitations of any kind in order to serve their native load, and nothing in section 217 suggests that LSEs should not be required to comply with reasonable requirements that are necessary to prevent undue discrimination and maintain a reliable transmission system. The conditions that have been established for taking network transmission service are reasonable and support these goals, and we therefore disagree that such conditions are inconsistent with the requirements of section 217. Furthermore, as Newmont Mining points out, the legislative history of section 217(b)(2) supports the interpretation that section 217 was intended to be consistent with the Commission's authority under sections 205 and 206 of the FPA to ensure that rates are just and reasonable and not unduly discriminatory or preferential, under which the designation requirements in Order No. 888 were adopted.

1494. We also disagree with commenter arguments that the Commission's requirements for eligibility for designation as a network resource impermissibly conflicts with state-mandated procurement plans. We point out that, with the exception of some clarifications on the types of LD provisions that are acceptable in designated firm LD products and what information a customer designating a system purchase or a seller's choice contract must provide, the requirements for designation of network resources are not new. Order No. 888 has long required that contracts be executed and imposed reasonable restrictions on the types of resources that may be designated as network resources.

1495. To the extent that individual transmission providers have unique circumstances or needs that justify a variation from the *pro forma* OATT, those parties can request such a variation and explain why their proposed variation is consistent with or superior to the requirements of the *pro forma* OATT in a section 205 filing. In particular, Nevada Companies' request for approval of a contract demand service in order to address certain issues presented by their unique situation would properly be made in the context of a section 205 filing requesting a deviation from the *pro forma* OATT. We agree with Newmont Mining and Utah Municipals that approved variations, if any, must be applied on a comparable basis to both the transmission provider's merchant function and the other network customers.

(4) General

Comments

1496. A number of commenters raised other general concerns regarding the designation of network resources. TAPS requests that the Commission clarify that conditional firm transmission service is sufficiently firm to meet the requirement that third-party transmission arrangements to deliver a designated purchase to the network be noninterruptible. TAPS also requests that the Commission provide for designation of network resources within the control area on a conditional firm basis.

1497. In its reply comments, South Carolina E&G request clarification of the content and process of making information postings in accordance with section 29.2 of the *pro forma* OATT. South Carolina E&G argues that, taken literally, section 29.2 requires that everything in an application for network service be posted. South Carolina E&G contends, however, that the contents of an application do not fit on OASIS as currently configured, and that making such information available on OASIS is not necessary for the Commission's purposes, particularly given the Commission's representations in favor of preserving the integrity of customer confidential information. South Carolina E&G suggests the Commission require only the following information to be posted on OASIS: identification of the service type as ''network''; identification of the source by name of the generator or system; identification of the sink by name of the network customer's load; identification of the point of receipt by specification of the interface at which the network customer intends to deliver to the resource into the transmission provider's transmission area; and identification of the point of delivery and sink.

1498. South Carolina E&G also requests clarification on how designated network resources are to be posted. South Carolina E&G asks, for instance, whether the Commission expects transmission providers to develop an OASIS template that network customers can update, as necessary, for network resources to simply be posted in PDF format, or be accomplished via the comment section of an OASIS reservation. South Carolina E&G argues that posting via the comment section of OASIS allows for operational ease, but provides limited transparency and includes administrative challenges due to character limitations and formatting constraints. Alternatively, South Carolina E&G argues, new functionality on OASIS that allows customers to post,

[875] *Florida Power Corp*, 81 FERC ¶ 61,247 (1997) (*Florida Power*).

modify and update network resources would satisfy the Commission's requirements, but would involve added costs and time.

1499. TranServ seeks clarification as to the minimum term, if any, that the transmission provider must honor for designation of new network resources. TranServ requests that network resources be allowed to be designated for the same minimum time periods used for firm point-to-point service, *i.e.*, daily or hourly service. Conversely, South Carolina E&G argues in its reply comments that requiring transmission providers to update their list of designated network resources on an hourly basis is too burdensome. South Carolina E&G requests that the Commission allow alternative methods of designating network resources on a short-term basis, such as adding comments to the appropriate comment field on either eTags or OASIS reservations.

1500. TDU Systems argue that the designation of network resources (explicit or implicit) by some transmission providers is automatic, while network customers are required to pay for elaborate studies of every conceivable path affected by the addition of the resource. TDU Systems request that the Commission clarify that the process of network resource designation should be the same for all network users.

1501. APPA, Fayetteville, NCPA, Northwest Parties, TAPS, and Wolverine request that clarifications made to the Commission's policy for qualification as a network resource apply prospectively and/or that sufficient time be allowed after the adoption of the Final Rule such that the necessary products, information systems and business practices can be developed. Such commenters contend that the designated network resources they currently rely upon were acquired and designated consistent with prior Commission precedent, so that changes to the network resource criteria established in this proceeding should not invalidate the continued use of such resources. Because there may be many existing designated network resources that do not meet the standards that the Commission eventually sets, Duke suggests on reply that the Commission may need to permit existing contractual designated network resources that do not qualify under the new standard to retain their designated status until the earlier of the expiration data of the transaction or the expiration date of any necessary transmission service supporting that network resource.

1502. In its reply comments, Dynegy disagrees with request to grandfather existing designated network resources, and argues that the Commission's holding in *Dynegy* was erroneous and should be remedied in its entirety, without the creation of yet another class of grandfathered entities.

Commission Determination

1503. The Commission agrees with TAPS that firm point-to-point transmission service provided on a conditional firm basis is sufficiently firm to be used for transmission to import a designated network resource. Firm point-to-point transmission service provided on a conditional firm basis meets the existing requirement that transmission arrangements in other control areas delivering power purchases designated as network resources to the network customer's transmission provider must not be interruptible for economic reasons, as explained further in section III.F of this Final Rule. With respect to TAPS' second request for clarification to allow for designation of network resources within the control area on a conditional-firm basis, we note that such designation of network resources within the control area will not be allowed, as discussed further in section III.F.

1504. In response to South Carolina E&G's request, we reiterate that not all of the information required by section 29.2 of the *pro forma* OATT for designation of a network resource will be made publicly available on OASIS. As discussed above, information about operating restrictions and generating cost will be masked to protect commercially sensitive information. South Carolina E&G has also requested clarification of the Commission's intent with respect to how designated network resource information is posted. Our existing regulations specify the view, download, and query requirements for information posted regarding network resource designations.[876] The details of how those informational postings are accomplished are best left to be determined as part of the NAESB standards development process.

1505. TranServ requests that the Commission clarify the minimum term, if any, that a transmission provider must honor for designations of new network resources. We agree with TranServ that the minimum term should be the same as the minimum time period used for firm point-to-point service (*i.e.*, daily), unless otherwise demonstrated by the transmission provider and approved by the Commission.[877]

1506. In response to TDU Systems' request for clarification that the process of network resource designation should be the same for all users, we note that section 28.2 of the *pro forma* OATT already provides that ''[t]he Transmission Provider, on behalf of its Native Load Customers, shall be required to designate resources and loads in the same manner as any Network Customer under Part III of this Tariff.'' We encourage parties to utilize the Commission's Enforcement Hotline to report suspected abused of this process.

b. Documentation for Network Resources

NOPR Proposal

1507. In the NOPR, the Commission noted that transmission providers are responsible for verifying that the network customer has provided all the information required in section 29.2, but that transmission providers are not responsible for verifying that the generating units and power purchase agreements network customers designate as network resources satisfy the requirements in sections 30.1 and 30.7 of the *pro forma* OATT. However, the Commission also explained that the transmission provider continues to have the responsibility to verify that third-party transmission arrangements to deliver the purchase to the transmission provider's system are firm.

1508. The Commission proposed to require the transmission provider's merchant function as well as network customers to include a statement with each application for network service or to designate a new network resource that attests that, for each network resource identified in the application for service, (1) the transmission customer owns or has committed to purchase the designated network resource, and (2) the designated network resource comports with the requirements for designated network resources.

1509. If the network customer does not include an attestation when it confirms its request, the Commission proposed that the transmission provider will notify the network customer within 15 days of confirmation that its request is deficient and that, wherever possible, the transmission provider will attempt to remedy deficiencies in the request through informal communications with the network customer. If such efforts are unsuccessful, the Commission further

[876] *See* 18 CFR 37.6(a).

[877] *See, e.g., Entergy Services, Inc.*, 105 FERC ¶ 61,318 (2003), *reh'g denied in relevant part*, 109 FERC ¶ 61,216 (2004).

proposed that the status of the request on OASIS will be changed to ''retracted'' and the network customer's request will be terminated without prejudice to the network customer submitting a new request that includes the required attestation, after which the network customer will be assigned a new priority consistent with the date of the new request.

1510. In the event that the transmission provider or any network customer designates a network resource that it does not own or has not committed to purchase, or that does not otherwise comport with the requirements for designated network resources, the Commission proposed that it will deem the network customer to be in violation of the *pro forma* OATT and will consider assessing civil penalties on a case-by-case basis consistent with the Commission's Policy Statement on Enforcement. The Commission encouraged the transmission provider and other market participants to use the Commission's Enforcement Hotline to report instances when they believe a network customer has designated as a network resource a resource that does not meet the criteria for network resources.

Comments

1511. Several commenters support the overall proposed changes involving attestation requirements, claiming the proposal should help to eliminate abuse, including the practice of some utilities denying transmission requests in order to accommodate its merchant function's plans to engage in future short-term purchases to serve native load.[878] Entegra explicitly supports the Commission's proposal to treat failures to comply as violations of the *pro forma* OATT subject to enforcement. Pinnacle notes that customers should make such attestations in good faith, such that an inadvertent error or omission would not automatically result in recourse to a legal remedy if it can be corrected without adverse impacts.

1512. Dynegy argues in its reply comments that transmission customers who knowingly provide false or inaccurate information in their network resource designations not only jeopardize reliability, but are essentially engaging in theft. Dynegy argues that such parties should be subject to the sanctions and penalties under the Market Behavior Rule,[879] including revocation of the violator's market-based rate authority. APPA and TAPS argue that the new attestation requirements should be consistently applied to all network customers, including the transmission provider's merchant function and affiliates.

1513. Several commenters support the Commission's determination that transmission providers are not required to independently verify the accuracy of an application for network service.[880] Some commenters request that the Commission clarify that transmission providers or transmission owners can voluntarily seek information which verifies that contractual terms meet the requirements in section 30.1 and 30.7 of the *pro forma* OATT.[881] In its reply comments, Duke argues that, without the ability to request the contracts supporting the compliance with the requirement that the designated network resources are firm enough, the Commission may not have authority to require that the network customer support its designation in situations where the network customer is nonjurisdictional.

1514. Pinnacle disagrees with the NOPR proposal that transmission providers should continue to be responsible for verifying the firmness of the network customers' transmission arrangements on other systems. Instead, Pinnacle contends that the transmission customer should have the obligation to ensure that their transmission arrangements meet the requirements needed to ensure that their resources qualify as designated network resources. In its reply comments, Detroit Edison also requests that the Commission require proof that network customers have obtained the requisite transmission service on external systems.

1515. Dynegy, in its reply comments, requests that network resource information and validity of designation be verified not only by the designating customer, but also by the seller or owner of the generation, in order to help ensure that all network resources are in fact backed by capacity. Entegra similarly suggests that the Commission require that entities designating network resources make periodic OASIS postings that will permit verification that the entity designating a generating facility as a network resource actually has rights to power from that facility.

1516. EEI and Entergy allege that the Commission's NOPR attestation proposal may have unintended consequences. Some commenters contend that the gap between the Commission's interpretation of the qualifications of network resources and current procurement practices creates a significant possibility that, if the Commission enforces its policies, it could cause substantial disruptions of service to network and native loads, reduce supply options, or expose network customers and transmission providers to increased liability.[882] EEI asserts that this is because a significant number of network customers and transmission providers are serving their network loads and native loads using resources, particularly power purchase contracts, that may not meet the Commission's requirement for designation as network resources. Some commenters request that the Commission engage in a comprehensive review of power purchase practices before implementing its proposed attestation requirement, and apply any change in policies only to power purchases entered into after the effective date of the Final Rule and after the industry has had time to develop new products that meet the Commission's requirements.[883]

1517. Entegra replies that the expressed concern about the attestation requirement by EEI is puzzling and troubling, because the NOPR did not propose to change the current requirements of the *pro forma* OATT regarding the qualification of network resources. Entegra argues that the widespread non-compliance alleged by EEI makes adoption of an attestation requirement more important and that EEI's allegations may, at most, suggest that the Commission consider some sort of amnesty for network customers and transmission providers willing to self-report and commit to full compliance with the network resource rules going forward.

1518. To ensure that network customers can submit requests for new network service without a final, executed contract, Entergy requests that an attestation to designate a new network resource should not be required until the service request is confirmed. If the request is pre-confirmed, Entergy suggests that the attestation should be provided at the time the request is submitted.

1519. SPP requests that the Commission not require it to police the additional restrictions on the designation of network resources proposed in the NOPR. SPP states that it has neither the data nor the personnel

[878] *E.g.*, Ameren, Entegra, Pinnacle, Public Power Council, and Southern.

[879] *See Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations*, 105 FERC ¶ 61,218 (2003).

[880] *E.g.*, Ameren, EEI, Suez Energy NA, Nevada Companies, and Utah Municipals.

[881] *E.g.*, Ameren, Duke Reply, Entergy, and Pinnacle.

[882] *E.g.*, EEI, TDU Systems, Indianapolis Power Reply, and South Carolina E&G Reply.

[883] *E.g.*, EEI and Indianapolis Power Reply.

necessary to perform this function and that the Commission should rely on network customer verification, subject to Commission audits. TranServ suggests that the exact nature of how the customer would make the newly required attestation, as well as the treatment of OASIS requests failing to provide the required attestation, should be determined in the NAESB forum at the time when the technical requirements for processing network service requests on OASIS are established.

1520. Several commenters request that the Commission amend section 30.2 of the *pro forma* OATT to require network customers that designate network resources in an external control area also provide a certification from that control area's administrator that the resource being designated is not counted as a designated resource for another load on or off of the system.[884] TDU Systems disagree, arguing on reply that the Commission should not require these types of certifications. TDU Systems recommend, in the alternative, that LSEs on multiple systems should not have to undesignate network resources to serve off-system load, which would eliminate the need for such control area certification for such transactions. TDU Systems also argues that, in the absence of any evidence of abuse, the Commission should not further complicate a process that most market participants would agree is already overly complicated and burdensome.

Commission Determination

1521. The Commission adopts the NOPR proposal that transmission providers continue to be responsible for verifying that third-party transmission arrangements to deliver the purchase to the transmission provider's system are firm, but that transmission providers are not responsible for verifying that the generating units and power purchase agreements network customers designate as network resources satisfy the requirements in sections 30.1 and 30.7 of the *pro forma* OATT. We also adopt the proposal to require both the transmission provider's merchant function and network customers to include a statement with each application for network service or to designate a new network resource that attests, for each network resource identified, that (1) the transmission customer owns or has committed to purchase the designated network resource and (2) the designated network resource comports with the requirements for designated network resources. The network customer should include this attestation in the customer's comment section of the request when it confirms the request on OASIS.

1522. If the network customer does not include the attestation when it confirms the request, the transmission provider must notify the network customer within 15 days of confirmation that its request is deficient, in accordance with the procedures in section 29.2 of the *pro forma* OATT. Whenever possible, the transmission provider shall attempt to remedy deficiencies in the request through informal communications with the network customer. If such efforts are unsuccessful, the transmission provider shall terminate the network customer's request and change the status of the request on OASIS to ''retracted.'' This termination shall be without prejudice to the network customer submitting a new request that includes the required attestation. The network customer shall be assigned a new priority consistent with the date of the new request.

1523. In the event that the transmission provider or any other network customer designates a network resource that it does not own or has not committed to purchase or that does not comport with the requirements for designated network resources, we will deem the network customer to be in violation of the *pro forma* OATT and will consider assessing civil penalties on a case-by-case basis, consistent with the Commission's Policy Statement on Enforcement.[885] We encourage the transmission provider and other market participants to use the Commission's Enforcement Hotline to report instances where they believe a network resource has been designated that does not meet the Commission's requirements.

1524. In response to Pinnacle's request that an inadvertent error or omission should not automatically result in a penalty if it can be corrected without adverse impacts, we reiterate the policy established in the Commission's Policy Statement on Enforcement that enforcement actions will not be imposed ''automatically.'' Enforcement actions are instead considered on a case-by-case basis after consideration of a number of factors which may result in penalties being reduced or eliminated.[886] Among the many factors to be considered pursuant to the Policy Statement on Enforcement is whether the violation is willful.[887] At the same time, consideration is provided for other factors that may weigh for assessing civil penalties, even in circumstances of inadvertent violations. For instance, the Commission considers whether the violator has a history of violations and whether the actions were recklessly or deliberately indifferent to the results.[888] While enforcement actions will not be automatic, and the inadvertence of a violation would be a consideration when determining what, if any, penalty to impose, there may be some instances where inadvertent violations would be found, after consideration as established in the Policy Statement on Enforcement, to warrant a penalty.

1525. Dynegy also requests that transmission customers who knowingly provide false or inaccurate information in their network resource designations be subject to the sanctions and penalties under the Market Behavior Rules,[889] including revocation of the violator's market-based rate authority. We reiterate that violations will be dealt with on a case-by-case basis in accordance with the Policy Statement on Enforcement.

1526. We reject requests to allow the transmission provider to voluntarily seek information which verifies that contractual terms meet the requirements in sections 30.1 and 30.7 of the *pro forma* OATT. Allowing transmission providers to verify terms and conditions of power purchase agreements would put transmission providers in the position of interpreting contracts and accepting or rejecting designations based on their interpretations. We believe such authority is unnecessary in light of the new attestation requirements and that instances of non-compliance are better handled by the Commission's enforcement staff in the context of audits and Enforcement Hotline reports. This applies equally to jurisdictional and nonjurisdictional customers. Every transmission customer must satisfy the requirements of the transmission provider's OATT in order to take service. The Commission thus has authority to require that all network customers support their designations.

1527. We disagree with Pinnacle's argument that transmission providers should not be responsible for verifying the firmness of the network customer's transmission arrangements on other systems. We find that having

[884] *E.g.*, MISO, Indianapolis Power Reply, and Detroit Edison Reply.

[885] *See supra* note 75.

[886] Policy Statement on Enforcement at P 13.

[887] *Id.* at P 20.

[888] *Id.*

[889] *Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations,* 105 FERC ¶ 61,218 (2003).

transmission providers verify firmness of such transmission arrangements provides a significant benefit to the system and is not unduly burdensome. The confirmation or lack thereof of service on the third-party's system should be readily available on OASIS. If firm third-party service is not confirmed in OASIS, the transmission provider should attempt to remedy any information deficiency in the request through informal communications with the network customer. If such efforts are unsuccessful, the transmission provider should find the request to designate the network resource deficient. Because this information is available on OASIS, we disagree with Detroit Edison's request that the Commission require proof that customers have obtained requisite transmission service on external systems.

1528. We also disagree with SPP's argument that it should not be required to police the additional restrictions on the designation of network resources, since it has neither the data nor the personnel necessary to perform this function. The only ''additional'' restrictions that the transmission provider is called upon to police is that network customers submit the appropriate attestations when requesting designation of a network resource, which places a particularly small burden on the transmission provider. We also do not expect the requirement that transmission providers verify the firmness of the network customer's transmission arrangements on other transmission systems to require any additional data or personnel.

1529. We reject Dynegy's request that the validity of network resource designations be verified not only by the designating customer, but also by the seller or owner of the generation, in order to help ensure that all network resources are in fact backed by capacity. Similarly, we deny Entegra's request that the customer be required to make additional, periodic OASIS postings to demonstrate that it has rights to the power from a designated resource. We find that such additional verifications are unnecessary in light of the new attestation requirements.

1530. With regard to arguments that requiring an attestation may disrupt service, the alleged confusion over the Commission's requirements for designation of network resources seems primarily concerned with whether the EEI Firm LD Product and similar products were eligible to be designated as network resources and whether certain resources can be designated both to serve native load and other network customers. As we have addressed both of these questions above, we believe that many of the concerns about the attestation requirement are resolved. Commenters have not supported claims that the attestation requirement will be either burdensome or that the requirement will require substantial time to comply. As noted above, the minimal additional network resource designation requirements impose in this Final Rule beyond the existing requirements are not expected to be unduly burdensome. While exceptions may be appropriate in cases of legitimate emergencies, we disagree with the implication that a customer should be granted general flexibility to designate a network resource that otherwise may not be eligible.

1531. In response to Entergy's request, we agree that attestations will not be required to be submitted until the service request is confirmed. However, if the request is pre-confirmed, we agree that the attestation must be provided at the time the request is submitted.

1532. In response to TranServ's request that the exact nature of how the customer would make an attestation should be determined in the NAESB forum, we note that the contents and the specific information that is required to be provided with the attestation are specified in the *pro forma* OATT, and we are requiring that the attestation be submitted through OASIS with each request to designate a new network resource. The appropriate subject for transmission providers to coordinate with NAESB to resolve is limited to the appropriate formatting of such information to be provided in OASIS. In response to TranServ's request that NAESB should also determine the treatment of OASIS requests where the customer fails to provide the necessary attestation, we point out that we have already directed that such requests are to be found deficient by the transmission provider and treated in accordance with the procedures in section 29.2 of the *pro forma* OATT.

1533. We reject requests to require network customers designating network resources in an external control area to provide certification from that control area's administrator that the resource being designated is not counted as a designated resource for another load on or off the system. We find that, in absence of any evidence that the Commission's new attestation requirements will be insufficient, this requested verification appears unnecessary.

c. Undesignation of Network Resources

1534. Section 28.2 of the *pro forma* OATT requires the transmission provider, on behalf of its native load customers, to designate resources and loads in the same manner as any network customer under Part III of the *pro forma* OATT (Network Integration Transmission Service). The information provided by the transmission provider must be consistent with the information it uses to calculate ATC. Section 30.3 of the *pro forma* OATT previously allowed the network customer to terminate the designation of all or part of a generating resource as a network resource at any time, but stated that the network customer should provide notification to the transmission provider as soon as reasonably practicable.

1535. In Order No. 888–B, the Commission clarified that the *pro forma* OATT allows network customers to designate network resources over shorter time periods. The Commission indicated that a network customer that seeks to engage in firm sales from its currently designated network resources may terminate the generating resource (or a portion of it) as a network resource pursuant to section 30.3 of the *pro forma* OATT and request that, as set forth in section 29 of the *pro forma* OATT, the same generation resource be designated as a network resource effective with the end of its power sale.[890]

NOPR Proposal

1536. In the NOPR the Commission proposed to continue to allow network customers to ''undesignate''[891] a portion of their network resources on a short-term basis to make off-system sales. The Commission reiterated that a network customer may redesignate the resource by making a request to designate a new network resource. Additionally, the Commission reiterated that the transmission provider and all network customers must designate their network resources and are prohibited from making firm third-party sales from designated network resources. The Commission stated that, to the extent the transmission provider or a network customer wants to make a firm sale from a network resource, it must undesignate the resource pursuant to section 30.3 of the *pro forma* OATT. The network customer, including the transmission provider itself, could request to redesignate the resource by making a request to designate a new network resource pursuant to section 30.2 of the *pro forma* OATT.

[890] Order No. 888–B at 62,093.

[891] The general term ''undesignation'' refers to both temporary terminations and indefinite terminations of network resource status, as discussed below.

1537. The Commission also sought comment on the amount of time prior to operation that the transmission provider and other network customers should be required to terminate a network resource to ensure that the appropriate set of network resources are included in the ATC calculation.

(1) Overview

Comments

1538. Most commenters appear to support the Commission's proposal to continue to allow network customers to undesignate a portion of their network resources on a short-term basis to make off-system sales. However, many commenters request clarification that a temporary undesignation will not cause them to forfeit their rights to transmission priority or ATC for any other time period. Several commenters also request that formal undesignations not be required or that the process not be burdensome. A wide range of comments were received in response to the Commission's request for comments on the amount of time prior to operation that the transmission provider and other network customers should be required to terminate a network resource to ensure that the appropriate set of network resources are included in the ATC calculation.

Commission Determination

1539. The Commission generally adopts the NOPR proposal to continue to require network customers and the transmission provider's merchant function to undesignate network resources or portions thereof in order to make certain firm, third-party sales from those resources. In particular, network customers and the transmission provider's merchant function may only enter into a third-party power sale from a designated network resource if the third-party power purchase agreement allows the seller to interrupt power sales to the third party in order to serve the designated network load. Such interruption must be permitted without penalty, to avoid imposing financial incentives that compete with the network resource's obligation to serve its network load.

1540. We clarify that requests to undesignate network resources that are submitted concurrently with a request to redesignate those network resources at a specific point in time shall be considered temporary terminations. Conversely, requests to undesignate network resources submitted without any concurrent request to redesignate those network resources shall be considered a request for indefinite termination of those network resources.

1541. We direct transmission providers to develop OASIS functionality and, working through NAESB, business practice standards describing the procedural requirements for submitting both temporary and indefinite terminations of network resources, to allow network customers to provide all required information for such terminations. Such OASIS functionality should allow for electronic submittal of the type of termination (temporary or indefinite), the effective date and time of the termination, and identification and capacity of resource(s) or portions thereof to be terminated. For temporary terminations, such OASIS functionality should also allow for electronic submittal of (1) effective date and time of redesignation, following the period of temporary termination; (2) information and attestation for redesignating the network resource following the temporary termination, in accordance with section 30.2 of the *pro forma* OATT; and (3) identification of any related transmission service requests to be evaluated concomitantly with the request for temporary termination. In response to TranServ's request, we clarify that the request for temporary termination of the resource and the requests for the related transmission service identified in item (3), if any, should be evaluated as a single request, and approved or disapproved as such. We specifically direct transmission providers, working through NAESB, to develop business standards describing the procedures for submitting and processing requests for concomitant evaluations of transmission requests and temporary terminations. When processing such requests, the evaluation of the transmission service requests identified in item (3) should take into account the undesignation of the network resources identified in the request for termination. However, the evaluation of the transmission service requests in item (3) should be processed taking proper account of all competing transmission service requests of higher priority.

1542. Consistent with the requirements for requests for designation of new network resources, the new OASIS functionality should also allow for queries of requests to undesignate and redesignate network resources. In accordance with section 37.6 of the Commission's regulations,[892] such requests must be able to be queried by the publicly available information posted on OASIS.

1543. Transmission providers need not implement this new OASIS functionality and any related business practices until NAESB develops appropriate standards. Prior to implementation of this new OASIS functionality, requests for temporary or indefinite terminations of network resources may be submitted by transmitting the required information to the transmission provider by telefax or providing the information by telephone over the transmission provider's time recorded telephone line.

(2) Risk to ATC Rights

Comments

1544. Most commenters request clarification that a temporary undesignation of a network resource does not constitute a forfeiture of priority followed by a new request to designate the network resource, or otherwise put in jeopardy the ATC associated with the designation of that resource for any period other than the period of undesignation.[893] Several commenters argue that virtually no network customers will ever make a firm third-party sale if they are forced to reapply for transmission service after a period of undesignation of their resource, since they would run the risk of losing the ATC associated with the resource.[894] EEI and Entergy contend that the result of such a policy would be that the industry would no longer be able to take advantage of the diversity of peak loads to make firm sales and purchases, and an almost immediate shortage of firm energy sources to serve network and native loads. Duke argues that the approach of not compelling network customers to risk losing the ATC associated with their designated resources beyond the period that the resource is designated would be the comparable approach vis-à-vis point-to-point customers seeking to temporarily redirect their service.

1545. Southern argues that to treat a redesignation as an entirely new application for network resource designation would appear to depart from existing tariff requirements and unnecessarily limit the reliability of network customers' service. It also argues that such an approach would be in contravention with section 217(b)(4) of the FPA, which directs the

[892] 18 CFR 37.6.

[893] *E.g.*, Duke, EEI, Entergy, Exelon, MDEA Reply, Northwest Parties, Pinnacle, Progress Energy, South Carolina E&G Reply, Southern, TDU Systems Reply, TranServ, and WSPP Reply.

[894] *E.g.*, Duke, EEI, Entergy, Progress Energy, South Carolina E&G Reply, and TranServ.

Commission to act in a manner that facilitates the planning and expansion of facilities to meet the reasonable needs of LSEs to satisfy the service obligations of the LSEs. Southern contends that the NOPR proposal would create administrative burdens on transmission providers, potentially treat network service as an inferior product to long term point-to-point transmission service, and introduce a substantial deterrent against optimization of network resources by network customers.

1546. On the other hand, Great Northern initially requests that ATC not be set aside for a former network resource in anticipation that it might be designated as a network resource at some time in the future. In order to ensure comparable treatment for all transmission service customers, Great Northern argues, the Commission should place new requests to designate network resources at the end of the transmission queue, regardless of the prior designation of those resources. Great Northern clarifies on reply that, while ATC should not be set aside for former network resources in anticipation that it might be designated as a network resource at some unspecified time in the future, it has no objection to setting aside ATC to be used by a formerly designated network resource after a temporary, specified period of undesignation such as one month or one season.

1547. NorthWestern, in its reply comments, disagrees with Great Northern's initial comments that new designations be placed at the end of transmission service queue regardless of the prior designation of those resources. NorthWestern argues that such a policy would unduly discriminate against the network customer who is paying for the use of the entire transmission system and grant an undue preference to the point-to-point customer. NorthWestern also argues that the proposal that ATC not be set aside for an undesignated network resource appears to conflict with the Commission's standard interconnection procedures for large and small generators. Once all upgrades specified through the interconnection process have been installed, NorthWestern contends that the generator can be specified as a network resource by any customer, at the time of commercial operation for the generator or at any time in the future.

1548. TAPS appears to support a requirement that transmission customers get back in the queue when re-designating resources, so long as the rules apply to transmission providers as well as network customers.

Commission Determination

1549. In response to the many requests and comments, we clarify that a request for termination of a network resource that is concurrently paired with a request to redesignate that resource at a specific point in time will not result in the network customer permanently forfeiting rights to use that resource as a designated network resource. Any change in ATC that is determined by the transmission provider to have resulted from the temporary termination shall be posted on OASIS during this temporary period. We agree that requiring network customers making temporary terminations to permanently forfeit rights to use this ATC would significantly reduce or eliminate firm third-party power sales. We emphasize, however, that a request to terminate a network resource that is not accompanied with a request to redesignate that resource at a specific point in time is to be considered an indefinite termination. After an indefinite termination of a resource, the network customer has no continuing rights to the use of such resource and future requests to designate that resource would be processed consistent with section 30.2 as a designation of new network resource.

1550. We disagree with NorthWestern's argument that, once upgrades specified through the interconnection process have been installed, the generator can be specified as a network resource by any customer, at the time of commercial operation of the generator or at any time in the future. The Commission has long noted that the generator interconnection process is separate and independent of the acquisition of transmission service for the same generator.[895] The fact that system upgrades may be required to interconnect a generator does not mean any network customer is entitled to the use of that generator at all times, even in the event that the network customer indefinitely terminates the designation of that resource. The integration of network resources with different network customers presents different effects and flows on the transmission system that must be evaluated by the transmission provider.

(3) Minimum Lead-Time

Comments

1551. EEI and Entergy argue that the Commission should not require transmission providers or network customers to undesignate a network resource for a specific amount of time prior to the commencement of an off-system sale. In many instances, EEI argues, short-term firm power sales are made with relatively little lead time, particularly after events such as forced outages or unusual weather conditions. EEI and PNM–TNMP argue that requiring transmission providers or network customers to undesignate a specific amount of time prior to an off-system sale would foreclose the possibility that firm sales could be made with short lead times. That, EEI argues, would adversely affect the sales market, without having any impact on ATC on the path used by the network resource because the network resource would not be undesignated. In EEI's view, imposing lead times on undesignations of network resources would also result in treating network and native load customers less favorably than point-to-point customers. EEI points out that the *pro forma* OATT does not impose any minimum lead times on firm redirects of point-to-point transmission service pursuant to section 22 of the *pro forma* OATT or reassignment of transmission service pursuant to section 23 of the OATT, despite the fact that advance notice of redirects might make the resultant ATC more marketable.

1552. Most commenters, however, appear to support the establishment of a minimum amount of time prior to operation that the transmission provider and other network customers should be required to terminate a network resource to ensure that the appropriate set of network resources are included in the ATC calculation, although they express widely varying opinions on what period of time would be appropriate.

1553. Ameren and Pinnacle contend that the amount of time prior to operation that the transmission provider and other network customers should be required to terminate a network resource should be linked to the frequency of the calculation that gets standardized in the ATC process. Pinnacle contends that, if the undesignation and redesignation are performed on OASIS as they propose, ATC could be recalculated and posted immediately following the undesignation or redesignation. Ameren contends that it cannot comment further until the parameters of the ATC process are defined. FirstEnergy states that the amount of time should be consistent with the time periods required in markets, and that outside of markets, times should be established that coincide with such markets. Southern argues that the current practice, under which a resource is undesignated when

[895] *See, e.g.*, Order No. 2003 at P 118, 744.

it schedules point-to-point transmission service for an off-system sale, provides adequate time to ensure that the appropriate set of network resources is included in the ATC calculation.

1554. PJM notes that, under its system, a generator resource with excess capacity can undesignate the excess resource on a ''day ahead'' basis. PJM believes that this is the proper amount of time needed to ensure resource adequacy. PJM argues that a generator should not, under any circumstance, change the designation of its resource ''same day.''

1555. TranServ argues that, at a minimum, a request for undesignation should be supplied no later than the firm scheduling deadline so that released capacity may be acquired on a non-firm basis. If that data were required to be submitted earlier than the scheduled deadline, TranServ suggests the transmission provider may be able to offer incremental capacity for firm sales. TranServ requests that the Commission establish in the *pro forma* OATT some nominal timeframe for network customers to provide to the transmission provider their planned use of designated resources to serve loads.

1556. Nevada Companies requests that, due to some system emergencies, force majeure events, and hourly scheduling of tie-line changes, they be allowed to change undesignation of network resources at any time to handle these types of events.

Commission Determination

1557. Commenters presented many alternative views in response to the Commission's request in the NOPR for comments on the appropriate minimum lead-time prior to operation that the transmission provider and other network customers should be required to terminate a network resource to ensure that the appropriate set of network resources are included in the ATC calculation. In consideration of these comments, the Commission finds that the appropriate requirement is that network customers not be permitted to make firm third-party sales from any designated network resource without (1) undesignating that resource for the period of the third-party sale pursuant to *pro forma* OATT section 30.3 and (2) providing notice of such undesignation before the firm scheduling deadline (10 a.m. the day before service commences). We find that this requirement strikes the appropriate balance, allowing undesignated capacity to be acquired on a non-firm basis but not creating an undue adverse effect on third-party sales.

1558. We find it unnecessary to incorporate into the *pro forma* OATT provisions relaxed rules for changing the undesignation of network resources at any time to handle system emergencies, force majeure events, forced outages or unusual weather conditions, as suggested by some commenters. Other procedures such as those in NERC's standard for Capacity & Energy Emergencies, EOP–002–2, or the possible use of capacity benefit margin, are more appropriate to deal with legitimate system emergencies. Outside the context of legitimate system emergencies, network customers should rely on appropriate planning and operation, rather than relaxed rules for designation of network resources.

1559. We disagree with EEI's argument that requiring a minimum lead-time will result in treating network and native load customers less favorably than point-to-point customers. In particular, EEI is incorrect in its statement that the OATT does not impose any minimum lead times on firm redirects of point-to-point transmission service or reassignments of transmission service. Firm point-to-point customers are also subject to deadlines for scheduling redirects pursuant to section 22.2 of the *pro forma* OATT. Furthermore, we find that EEI has provided no compelling evidence to support its argument that the adverse impacts on the market for firm energy with short lead times justifies having no minimum lead time.

(4) General

Comments

1560. Several commenters argue that the Commission should not require network customers or the transmission provider to make formal modifications to their designations of network resources when they make firm sales to third parties from those resources.[896] EEI and Southern argue that the practice of most network customers and transmission providers in the ten years since the Commission issued Order No. 888 has been that a network resource is undesignated for any period for which the customer requests firm point-to-point transmission service from the generator or a third party. This practice, EEI argues, has not resulted in any adverse impacts on reliability or on the availability of transmission service and that, to the contrary, selling energy from network resources on a firm basis instead of a non-firm basis frees up firm transmission capacity that otherwise would have to be reserved for the network customer. EEI and NRECA contend that requiring formal undesignations is substantially more cumbersome for network customers and transmission providers making off-system sales.

[896] *E.g.*, EEI, NRECA Reply, PNM–TNMP, and Southern.

1561. Progress Energy and TranServ argue that network customers should not have to go through the process of redesignating a network resource as new when the network customer once again needs to use this resource to serve network load. TranServ argues that such a transaction is exactly analogous to a redirect of firm point-to-point service on a firm basis and requests clarification of whether the provider should evaluate a request to undesignate a network resource concomitantly with the assessment of that same customer's point-to-point request, as is done with redirects on a firm basis.

1562. NRECA states that the undesignation requirement is too burdensome and, therefore, the Commission should adopt a comparability requirement that would allow network customers to utilize the practice that many public utility transmission providers use today: *i.e.*, use designated resources for firm off-system transactions or third party uses without having to go through the designation, undesignation and redesignation process. NRECA argues that existing scheduling procedures have allowed transmission providers to deliver power from their designated network resources for off-system merchant purposes reliably and should perform equally well for network customers, provided they still pay a point-to-point charge for the ''outbound'' leg of a delivery to a neighboring network to serve the customer's network load on the neighboring network. NRECA argues in its reply comments that, whatever the Commission decides to do, comparability is the most important principle when considering the undesignation policy and that ''grandfathering'' agreements which would allow transmission providers to essentially get around this requirement would allow undue discrimination to continue. EEI disagrees in its reply comments with NRECA's assertion that transmission providers currently have an advantage over network customers, arguing that the same standards apply to the transmission provider's merchant function and network customers when they seek to make off-system sales from network resources.

1563. PNM–TNMP contends that the Commission has held that formal undesignation and redesignation are not required, so long as the transmission

provider treats its own resources and the network resources of network customers comparably. PNM–TNMP and Pinnacle further argue that to require formal undesignation and redesignation would appear to do nothing more than impose an extra layer of administration to the management of network resources, making power sales more difficult and potentially reducing financial benefits to end use customers. Bonneville argues that the Commission's proposals regarding the use of network resources for surplus sales are likely to raise the cost to consumers.

1564. Duke requests that the Commission clarify that any product that is not ''designatable'' as a network resource by a buyer may be sold by a seller that happens to be a network customer, without having to undesignate any network resources.

1565. Suez Energy NA requests that the Commission ensure that a utility cannot use redesignation to hoard transmission capacity in order to deprive independent power producers of access to the grid. It contends that a utility could consistently hold transmission to serve generation that never runs for economic reasons and, the day before power flows, redesignate that transmission to accommodate a third-party purchase, effectively using its ability to redesignate network transmission capacity to hoard scarce ATC. In order to prevent potential abuse, Suez Energy NA agrees with the NOPR proposal to require transmission providers to use the same OASIS procedures to designate and terminate network status for themselves that they apply to network customers.

1566. If the Commission requires formal designations and undesignations, EEI asks the Commission to clarify whether it is changing its policy that it is not necessary to modify service agreements in such circumstances in order to avoid requiring transmission providers to make numerous filings amending service agreements.[897] If formal undesignations are required, EEI argues on reply that each transmission provider would be required to submit a revised application for network service under section 29.2 of the *pro forma* OATT both at the time the resource was undesignated and at the time that resource was redesignated. EEI also argues that formal undesignation would require the execution and filing of revised network service agreements reflecting the changes.

1567. South Carolina E&G argues in its reply comments that off-system sales of firm power are typically in the form of a slice-of-system sale. South Carolina E&G requests that the Commission provide guidance for how to treat such a sale of power, suggesting that the transmission provider be permitted to undesignate a slice of a system sufficient to support the firm power sale and then, at the conclusion of the sale, redesignate that slice of the system as a network resource.

1568. While generally supporting the Commission's proposal to continue to allow network customers and the transmission provider, with respect to its native load, to undesignate network resources to allow them to make sales to third parties, some commenters seek certain changes, consideration, or clarification by the Commission.[898] EEI, joined by TDU Systems on reply, argue that the Commission should modify its statement that network customers should be permitted to undesignate network resources ''on a short-term basis to make off system sales.'' They argue that nothing in Order No. 888, the Commission's decisions, or the public interest requires that network resources be undesignated only for short-term sales. They further argue that such sales need not be ''off-system.'' Progress Energy argues that the Commission should only allow transmission customers to undesignate network resources to make firm off-system sales for a term which the transmission customer has adequate generation reserves to serve its network load. In its view, the transmission provider also must have the authority to deny the designation or undesignation of the network resources if the transmission provider determines that it needs the network resources to preserve the reliability of its transmission system or to ensure that there is sufficient transmission capability to support the requested changes. NRECA disagrees on reply, arguing that granting transmission providers the authority to deny undesignation requests would give them too much discretion and the perfect opportunity to discriminate.

1569. Progress Energy agrees with the Commission that network service involves the entire transmission provider's system and does not involve a contract path like point-to-point service. It also agrees that the delivery of a network resource once inside the system does not need to be redirected. Progress Energy notes that peaking resources have low capacity factors and, therefore, their transmission reservations are frequently underutilized. They request that network customers be given the ability to optimize their transmission purchases by bringing energy into the host transmission provider's system from other designated network resources in times when they are not using their peaking designated resources.

1570. MDEA, Progress Energy, and Entergy request that, for reliability and economic reasons, network customers be given the flexibility to substitute new designated network resources without abandoning the original transmission queue position of an existing designated network resource.[899] If the Commission does not change its proposal in order to provide network customers with this flexibility, Progress Energy contends that point-to-point service will be a superior service to network service.

1571. Entergy states that it is important for the Commission to recognize that the undesignation of network resources can be used by network customers as a means of allowing merchant generators the opportunity to displace existing resources in serving network and native load. It argues that the Commission should be wary of limiting the ability of a network customer to undesignate network resources, as any such restriction will have broader implications than just the ability of network customers, including the transmission provider's wholesale merchant function, to sell that resource off-system with point-to-point service.

1572. Entergy also requests that the Commission clarify that, while network customers cannot redirect network service, nothing in this prohibition prevents transmission providers from studying requests to designate new network resources as displacements of existing network resources. It argues that preventing network customers from using automated study functions would significantly hinder the ability of these customers to substitute their existing long-term resources with short-term purchases of energy and capacity from merchant generators when it is economical to do so.

1573. TDU Systems argue that network customers (and transmission providers to the extent they serve native load on other systems) should be able to schedule output on a firm basis from

[897] *See Virginia Electric and Power Co.,* 81 FERC ¶ 61,125 at 61,111–12 (1997), *reh'g denied,* 82 FERC ¶ 61,034 (1998).

[898] *E.g.,* EEI, Pinnacle, and Progress Energy.

[899] In its reply comments, MDEA requests that any such flexibility afforded to transmission providers also be available to network customers on a non-discriminatory basis.

network resources on one system to serve their network loads on neighboring systems without having to designate and redesignate network resources among the various transmission providers' control areas. TDU Systems state this would permit LSEs that serve across multiple systems to come closer to replicating the economic dispatch of control area operators, significantly reducing the cost of discharging their service obligations to the customers they serve.

1574. Xcel opposes requiring a transmission customer to undesignate a network resource even in a situation where the resource is used only transiently to provide off-system sales, arguing that such policy would have significant adverse consequences for customers across the country. It points out that it is native load customers that frequently benefit from purchase of economy energy and that, if an undesignation was required to deliver economy energy, most such transactions likely would not occur. Xcel also argues the NOPR concepts relating to designation of network resources and justification of economy energy purchases are irrelevant in the context of an RTO where energy is procured and dispatched throughout the RTO on a security constrained economic basis.

1575. EEI, joined by TDU Systems on reply, requests that the Commission clarify that any changes to the procedures for designating and undesignating network resources apply only to designations made after the Final Rule becomes effective, in order to avoid substantial adverse impacts on the reliability of service to network and native loads. Duke and Pinnacle request that the Commission require NAESB to develop standards that address undesignation and redesignation and allow sufficient time for the NAESB process and for OASIS tools to be developed and approved, prior to the implementation of a new policy. TranServ asks that the undesignation of network resources be supported on OASIS.

Commission Determination

1576. We disagree with commenters arguing that formal undesignations and/or redesignations of resources used to make firm third-party sales should not be required. The undesignation and redesignation requirements exists not only to promote reliability, but also to prevent undue discrimination, promote comparable treatment of customers, and increase the accuracy of ATC calculations. We find that the interest in advancing these policy goals overrides the minimal burden and cost that submitting undesignations and/or redesignations entails. We disagree with Xcel's argument that most economy energy purchases that benefit its native load customers likely will not take place if undesignation of network resources is required prior to firm, third-party sales. First, the requirement to undesignate network resources only applies to firm sales, while typical non-firm economy energy transactions would not require undesignation. Second, undesignating a network resource is not unduly burdensome, consisting only of electronically submitting several items of information, as described above. Therefore, we do not believe that a transaction prevented purely as a result of the requirement to undesignate network resources would have provided any significant economic value had it taken place.

1577. We find that requests to allow ''informal undesignations'' appear to be simply requests to not require undesignations at all. Since the salient feature of requiring an undesignation is that the proper account is taken of the effects on ATC, informal undesignations, which do not take proper account of the fact that a resource is no longer a designated network resource, appear to serve no purpose.

1578. With regard to PNM-TNMP's argument that the Commission has held that formal undesignation and redesignation are not required, so long as the transmission provider treats its own resources and the network customer's resources comparably, we believe PNM-TNMP misunderstands our policies. We note that PNM-TNMP provides no citation to Commission precedent to support its statement.

1579. Duke requests clarification as to whether a network customer must undesignate a network resource in order to make a third-party sale from that resource if the third-party sale would not itself qualify to be designated as a network resource. We reiterate the existing requirement that designated network resources must not be committed for sale to non-designated third-party load or include resources that otherwise cannot be called upon to meet the network customer's network load on a noninterruptible basis. We find that a resource is ''committed for sale to a non-designated third party load'' if a power purchase agreement for the sale from that resource provides for penalties if service to the third party is interrupted in order to serve the designated network load.

1580. In response to comments by EEI, NRECA, and Suez Energy NA, we reiterate that all parties, including transmission providers serving their native loads, are subject to these requirements for designation and undesignation of network resources. Section 28.2 of the *pro forma* OATT clearly provides that transmission providers are required to designate resources and loads in the same manner as any network customer. We encourage parties suspecting that transmission providers or other network customers are not conforming to the requirements for designating or undesignating network resources to report their concerns using the Commission's Enforcement Hotline.

1581. EEI has requested clarification of whether the Commission is changing its policy that transmission providers do not need to modify network service agreements when network resources are undesignated and redesignated. We have not proposed and do not intend to begin requiring that network customers file modified service agreements when network resources are designated or undesignated. As we explained in *Dayton Power and Light Co.*,[900] ''changes in network resources may require the customer to file a request under OASIS, but a change to the information recorded initially in the network service agreement is not a requirement.'' EEI also argues that, if formal undesignations are required, then each transmission provider would be required to submit a revised application for network service under section 29.2 of the *pro forma* OATT, both at the time the resource was undesignated and the time that resource was redesignated. We disagree. There is no requirement that a transmission provider submit a revised application for network service every time a resource is designated or undesignated.

1582. In response to a request by South Carolina E&G, we clarify that firm third-party sales may be made from an undesignated portion of a network customer's network resources (*i.e.*, a ''slice-of-system sale''), so long as all of the applicable requirements are met. In particular, the network customer must submit undesignations for each portion of each resource supporting the third-party sale. If the undesignation is temporary, then the request must be accompanied by a request to redesignate the resource(s) on a specific date. When the undesignation takes effect, the network customer must update the capacities specified in its list of designated network resources posted on OASIS.

1583. We agree with EEI and TDU Systems' comments that there should be

[900] 93 FERC ¶ 61,331 at 62,128 (2000).

no minimum term for undesignations. We also agree with EEI and TDU Systems' arguments that network customers should not be restricted to temporarily undesignating network resources only for use in off-system sales, and clarify that network customers are not so restricted.

1584. We agree with Progress Energy that network customers should only make firm third-party sales when they have sufficient generation reserves to serve their loads. However, the purpose of the *pro forma* OATT is to provide nondiscriminatory transmission access, not to enforce generation adequacy requirements.

1585. With regard to Progress Energy's request for flexibility to evaluate potential impacts to the transmission system related to the undesignation and redesignation of network resources, we find that situations where undesignations cannot be accommodated due to transmission constraints should be extremely rare, such as highly-extraordinary counterflow situations. In such rare situations, the transmission provider should attempt to remedy the situation without denying the undesignation. If it is determined that the resource cannot be undesignated without jeopardizing reliability, then the transmission provider may deny the request for undesignation.

1586. We share NRECA's concern that allowing transmission providers to deny undesignations for reliability reasons could give a direct market competitor a significant opportunity to discriminate, but must weigh this concern against our significant interest in preserving reliability. We point out that transmission providers denying requests for service or changes to service because of reliability concerns must post a description of such denials in accordance with section 37.6(e)(2) of the Commission's regulations.[901] Again, we encourage any parties with concerns about denials of service or changes to service by a transmission provider for reasons of reliability to report their concerns to the Commission's Enforcement Hotline.

1587. We deny requests by MDEA, Progress Energy, and Entergy that network customers be given the flexibility to substitute new designated network resources without abandoning the original transmission queue position of an existing designated network resource. These parties seem to be requesting that a network customer be allowed to be ''first in line'' to use the ATC freed up by an undesignation of a network resource, as long as the network customer uses that ATC to designate an alternate resource. We disagree. Granting this request would, without any apparent justification, put point-to-point customers seeking ATC freed up by an undesignation at a disadvantage. We also disagree that, if the Commission does not allow network customers this flexibility, point-to-point service will be a superior service to network service. Progress Energy seems to be arguing that the point-to-point customer's ability to engage in a redirect affords that customer more flexibility than the network customer. We point out that redirects of point-to-point service on a firm basis are only on an ''as-available'' basis. Firm point-to-point customers cannot redirect unless ATC is available to support such a redirect after all higher-priority requests have been accommodated.

1588. Entergy has requested clarification that, while network customers cannot redirect network service, nothing in this prohibition prevents transmission providers from studying requests to designate new network resources as displacements of existing network resources. Although Entergy's request is unclear, we reiterate that redirects are not allowed within the context of network service and that network customers are not ''first in line'' to use ATC freed up by their undesignation of another network resource. Such requests must be processed taking proper account of all competing transmission service requests of higher priority.

1589. We disagree with TDU System's argument that network customers should be able to schedule output on a firm basis from network resources on one system to serve their network loads on neighboring systems without having to designate and redesignate network resources among the various transmission providers' control areas. Allowing network customers to not formally undesignate and redesignate network resources, even only when using those resources to serve their network loads on neighboring systems, will necessarily result in inaccurate evaluations of ATC. We reiterate that the burden associated with undesignating and redesignating the resources is particularly light and find that requiring network customers to make temporary undesignations when making third-party firm sales is thus justified in light of the ATC-related benefits.

1590. Xcel argues that the concepts relating to designation of network resources are irrelevant in the context of an RTO where energy is procured and dispatched throughout the RTO on a security constrained economic basis. We agree that Day 2 RTOs do not use the physical rights model contemplated under the *pro forma* OATT and, hence, not all the provisions discussed here are directly applicable to Day 2 markets. However, as we explain in section IV.C.2, RTOs and ISOs must make the necessary filings to comply with the Final Rule, or demonstrate that their existing tariff provisions are consistent with or superior to the terms of the revised *pro forma* OATT.

1591. We agree with parties arguing that network customers should not be required to use the new NAESB processes and OASIS tools to be developed in response to this section until such time as the NAESB standards and OASIS functionality have been developed and implemented. However, once the new standards and functionality are in place, network customers must use these new procedures to undesignate (whether temporarily or as part of an indefinite termination) any network resources, regardless of the date that those resources were originally designated.

7. Clarifications Related to Network Service

a. Secondary Network Service

1592. Section 28.4 of the existing *pro forma* OATT allows a network customer to deliver energy to its network load from non-designated network resources on an as-available basis without additional charge, referred to as secondary network service. In Order No. 888, the Commission described such energy as non-firm economy energy purchases used to displace firm network resources.[902]

1593. The use of secondary network service to deliver purchased power when a network customer is making off-system sales has been raised in several Commission investigations and audits. In *Idaho Power*, the Commission accepted a settlement with Idaho Power related to Idaho Power's incorrect use of the native load priority to access its transmission system.[903] In *Idaho Power*, the utility's wholesale merchant function purchased power outside of Idaho Power's control area to facilitate an off-system sale and used secondary network service to bring the purchases into Idaho Power's control area.[904] In accepting the settlement, the Commission stated that ''[i]t is axiomatic that the native load priority

[901] 18 CFR 37.6(e)(2).

[902] Order No. 888 at 31,751.

[903] *Idaho Power Co.*, 103 FERC ¶ 61,182 at P 2 (2003) (*Idaho Power*).

[904] *Id.* at P 4.

cannot be used to complete sales that are not necessary to serve native load.'' [905] In *MidAmerican*, the Commission issued an audit report that contained a finding that MidAmerican's wholesale merchant function used network service instead of point-to-point service to deliver short-term energy purchases to its control area that were not used to serve MidAmerican's native load.[906]

NOPR Proposal

1594. In the NOPR, the Commission proposed to clarify that a network customer may not use secondary network service to import energy onto its system to support an off-system sale if the purchased power does not displace the customer's own higher cost generation. The Commission therefore proposed to modify section 28.4 of the *pro forma* OATT to state that a network customer may use secondary network service only to deliver economy energy and to define ''economy energy'' as energy purchased by a network customer that displaces the customer's own higher cost generation for the purpose of serving the customer's designated network loads. The Commission further explained that all participants engaging in purchases for resale must compete on a comparable basis and use point-to-point service to complete all segments of a purchase for resale off-system.

(1) Overview

Comments

1595. Several commenters agree with the Commission and support the proposed clarification regarding the use of secondary network service.[907] Alberta Intervenors state that such a restriction ensures fair competition among network customers and preserves the entitlement of native load customers.

1596. Other participants oppose the proposal, arguing that it is too broad and would interfere with legitimate activity by network customers.[908] EEI points out that, if a network customer is using all available network resources but is still purchasing energy from non-designated network resources to meet its peak native load, the network customer would need to rely on secondary service to transmit this purchase. In EEI's view, the Commission's proposal would prevent this customer from using secondary service for this non-economy energy, thereby interfering with its service obligations. To avoid such cases, EEI, Pinnacle, and PGP recommend that secondary service not be limited to economy energy only. NRECA states that the Commission's proposed limitation on the use of secondary service would prevent network customers from meeting their native load obligations in cases of extreme weather and power outages. NRECA asks the Commission to state explicitly in section 28.4 of the *pro forma* OATT that secondary service may not be used to facilitate off-system third party sales, but rather must be used to import power needed to serve network load economically and efficiently. Entergy suggests the Commission abandon the limitation and specify simply that secondary service cannot be used to serve loads other than the network or native load.

1597. Others argue that the restriction of secondary service to only economy energy would have unintended consequences regarding the purchase of renewable resources. Emerald, Flathead, and the Northwest Parties state that, for reasons of customer demand or contractual obligation, network customers may be required to purchase renewable power that generally is more expensive than traditional thermal or hydro electric generation. These purchases could displace less expensive non-renewable resources, resulting in the need for the network customer to make off-system sales of the non-renewable resources. Emerald, Flathead, and Northwest Parties suggest that the Commission revise the definition of ''economy energy'' to include an exception for renewable energy. TAPS raises a similar issue, asking the Commission to clarify that economy purchases as well as substitute resources qualify for use of secondary service.

1598. EEI argues that the proposed limitation on secondary service would require all network customers to engage in a specific form of Commission-regulated economic dispatch, while requiring transmission providers to evaluate each resource and become ''dispatch police.'' Entergy, SPP, and PGP agree. They assert that calculating the ''cost'' of power is problematic, inherently subjective and burdensome because transmission providers lack the necessary knowledge to perform this analysis. EEI, Entergy, SPP, and PGP instead suggest that the Commission conduct periodic audits of secondary service to ensure compliance with the requirements of OATT section 28.4 rather than transmission providers.

1599. Although Powerex supports the Commission's restriction on the proper use of secondary service, it also states that determining whether or not an import would qualify as ''economy energy'' would be difficult. Powerex requests that the Commission implement specific rules in advance of such transactions to resolve uncertainty. It suggests a capacity test to prevent preferential acquisition of generation capacity, a tariff prohibition on the use by the network customer or its energy affiliates of any export transmission capacity made available on another intertie, and the modification of business practices governing curtailment. In reply, Alberta Intervenors agree with Powerex's proposed changes to curtailment practices, but disagree with the other two elements. Alberta Intervenors assert that the tariff prohibition causes inefficient use of ATC and that the capacity test is not a stand-alone test and, as a result, would only be helpful as a supplement to the ''economy energy'' test.

1600. Some participants raise other issues not addressed in the NOPR. South Carolina E&G asks that the Commission clarify its policy on purchases of economy energy, as well as provide a clear definition of the acceptable trading practices—notably parking, hubbing, and lending—under the current *pro forma* OATT. Emerald and Flathead request the Commission to revise the definition of ''network load'' in section 1.24 of the *pro forma* OATT to allow point-to-point and network service to the same discrete point of delivery. Morgan Stanley asks that the Commission explain why using secondary service to make an off-system purchase while there is any off-system sale during the same interval is improper and whether the Commission will prohibit such activity only if the off-system purchase and sale are part of a single transaction. Finally, Xcel argues that the concepts relating to designation of network resources are irrelevant in the context of an RTO where energy is procured and dispatched throughout the RTO on a security constrained economic basis.

Commission Determination

1601. In general, the Commission agrees with parties that favor an expansion of the proper use of secondary network service. Although we affirm our finding in *MidAmerican*,[909] the Commission

[905] *Id.*

[906] *MidAmerican Energy Co.*, 112 FERC ¶ 61,346 at P 6 (2005).

[907] *E.g.*, Alberta Intervenors, Southern, Suez Energy NA, and TAPS.

[908] *E.g.*, EEI, Entergy, Northwest Parties, NRECA, Pinnacle, PGP, Southern, and Xcel.

[909] *MidAmerican Energy Co.*, 112 FERC ¶ 61,346 at P 6 (2005) (*MidAmerican*). Following an audit, the Commission found that MidAmerican's

recognizes that there are instances outside the proposed definition of economy energy that warrant the use of secondary service in order to serve network loads reliably. The Commission therefore declines to adopt the definition of economy energy proposed in the NOPR and, instead, will retain the existing section 28.4 that permits use of secondary network service ''to deliver energy to its Network Loads.''

1602. With respect to Powerex's comments, we reject the requested clarifications as Powerex has not fully supported the use of its proposed capacity test or other measures and has not demonstrated that such test would not preclude legitimate uses of this priority as noted in the NOPR. If parties suspect inappropriate use of secondary network service, they may report the suspected activity to the Commission's Enforcement Hotline or file a compliant with the Commission pursuant to FPA section 206. Furthermore, the Commission's staff will continue to provide oversight of all tariff-related activities through its enforcement program.

(2) ''On an as-available basis''

1603. Section 28.4 of the existing *pro forma* OATT allows a network customer to use secondary network service to deliver energy purchases to its network load from non-designated resources ''on an as-available basis.'' However, the current *pro forma* OATT does not specify how a network customer must arrange for secondary network service.

NOPR Proposal

1604. In the NOPR, the Commission proposed to modify section 28.4 of the *pro forma* OATT to clarify that a network customer does not need to file an application for network service to receive secondary service. Instead, the customer must merely request such service on OASIS in a manner consistent with *pro forma* OATT sections 18.1 and 18.2 (Procedures for Arranging Non-Firm Point-to-Point Transmission Service).

Comments

1605. TDU Systems requests that the Commission clarify that time constraints located in OATT section 18.3 are not applicable to secondary service. Section 18.3 provides that requests for non-firm point-to-point service shall not be made before certain specified periods (more than 60 days in advance for monthly service, more than 14 days in advance for weekly service, *etc.*). TDU Systems states that some of its members currently use secondary service to access economy off-system purchases where intervening transmission constraints preclude the designation of those resources as network resources for long periods of time. Application of the non-firm point-to-point service request deadlines would impair TDU Systems' ability to rely on secondary service in those instances since they would extend beyond the timing requirements set forth in section 18.3.

Commission Determination

1606. The Commission clarifies that secondary service must be requested in accordance with section 18, including the timing restrictions set forth in section 18.3, of the *pro forma* OATT. Secondary service is on an as-available basis, and network customers should not be permitted to lock in such service in advance of other non-firm uses of available transmission. Allowing lower-priority secondary service to have a scheduling advantage over non-firm transmission would be inappropriate and would discourage the use of non-firm transmission service, thereby minimizing the revenue credits from non-firm transmission service that benefit all firm transmission customers.

(3) Redirect of Network Service

1607. The current *pro forma* OATT does not include any provision to change the point of receipt for an off-system designated network resource in a manner similar to redirect of point-to-point service. We are aware, however, that several transmission providers have posted business practices that allow network customers either to substitute an off-system non-designated network resource for a designated network resource or to redirect the point of receipt associated with an existing network resource.

NOPR Proposal

1608. The Commission proposed to clarify that network customers may not redirect network service in a manner comparable to redirect of point-to-point service, as network service involves no identified contract path and is, therefore, not a directable service. Should a network customer wish to substitute one designated network resource for another, the Commission stated that it must terminate the existing resource and designate a new one. The Commission explained that the network customer could also request to redesignate its original network resource by making a request to designate a new network resource. Alternatively, a network customer could use secondary network service when it wants to substitute a non-designated network resource for a designated network resource on an as-available basis.

Comments

1609. MISO strongly supports the Commission's clarification stating that network service is not a directable service and believes that the proposal appropriately clarifies the Commission's policy on redirect service. TDU Systems and NRECA, however, believe that the Commission should allow redirects of network service to deliver an LSE's resources. TDU Systems assert that redirect of network service is critical to LSEs serving native load across multiple transmission systems because it allows the amount of flexibility necessary to manage power supply costs. In addition, in TDU Systems' view, redirects have no effect on system reliability.

1610. EEI argues on reply that it is unclear why redirects of network service should be allowed. The advantage of redirecting firm point-to-point service is that the customer does not have to pay an additional charge for transmission service. However, both TDU Systems and NRECA agree that network customers should pay an additional charge for transmission service from network resources to off-system loads.

1611. Sacramento alternatively recommends that the Commission remove the ban on off-system sales in order to maximize efficiency in allocating transmission capacity. Occidental requests that the Commission place all transmission, including on behalf of native load, under the OATT guidelines to ensure that service is provided in a non-discriminatory fashion.

Commission Determination

1612. The Commission clarifies that network customers may not redirect network service in a manner comparable to the way customers redirect point-to-point service. Point-to-point service consists of a contract-path with a designated point of receipt and point of delivery. Network service has no identified contract-path and is therefore not a directable service. Network service instead provides for the integration of new network resources and permits designation of another network resource, which has the same practical effect as redirecting network service. If the customer wants to permanently

wholesale merchant function used network service instead of point-to-point service to deliver short-term energy purchases to its control area that were not used to serve MidAmerican's native load. The Commission stressed that the use of secondary network service is not for the purpose of serving off-system sales. *Id.* at P 6. The modifications to section 28.4 adopted in this Final Rule do not alter that limitation.

substitute one designated network resource for another, it should terminate the designation of the existing network resource and designate a new network resource. The customer could then simply request to redesignate its original network resource, if it so desires, by making a request to designate a new network resource. The ability of a network customer to also temporarily substitute one designated network resource for another is addressed in section V.D.6.

1613. The Commission rejects Sacramento's proposal to remove the ban on off-system sales. Network service is not based upon making off-system sales, but rather on integrating a network customer's resources with its load. Transmission providers must take point-to-point transmission service for off-system sales and network customers should be treated comparably. The Commission also rejects Occidental's request to place all transmission, including on behalf of native load, under the *pro forma* OATT. In Order No. 888–A the Commission clarified that a ''transmission provider is not required to 'take service' under its own tariff for the transmission of power that is purchased on behalf of bundled retail customers.'' [910] However, the Commission required that transmission providers, pursuant to section 28.2 of the *pro forma* OATT, must designate network resources and network loads in the same manner as any network customer. Occidental offers no explanation why the existing requirement of section 28.2 is not sufficient to address its concerns.

b. Behind the Meter Generation

1614. In Order No. 888, in response to customers with load served by ''behind the meter'' generation that sought to eliminate such load from their network calculation, the Commission found that a customer may exclude a particular load at discrete points of delivery from its load ratio share of the allocated cost of the transmission provider's integrated system. The Commission determined, however, that customers electing to do so must seek alternative transmission service, such as point-to-point transmission service, for any load that has not been designated as network load for network service.[911] In Order No. 888–A, the Commission stated that it would permit a network customer to either designate all of a discrete load as network load under the network integration transmission service or to exclude the *entirety* of a discrete load from network service and serve such load with the customer's behind the meter generation and/or through any point-to-point transmission service.[912]

1615. The Commission did not address the subject of behind the meter generation in the NOPR. A few commenters nonetheless proposed revisions to the *pro forma* OATT to require netting of a network customer's behind the meter generation against their network load as described in more detail below.

Comments

1616. Some commenters argue that, in order to meet the objective of eliminating discrimination in the provision of open access transmission service, the Commission must require comparable treatment between retail native load and network customers by allowing network customers to net behind the meter generation against their network load.[913] Specifically, such commenters argue that the Commission should modify the current pricing rules for network service to allow an LSE's load ratio share to reflect the reduction in load caused by behind the meter generation serving retail load.[914] In support of this position, these commenters argue that assigning transmission-related costs to customers that do not rely on the transmission provider's system to serve load is inconsistent with the Commission's cost-causation principles.[915] For example, CAC/EPUC contends that customer generation does not cause the transmission provider to incur costs when power is not being sold to or taken off the grid. Similarly, AMP-Ohio argues that it is inappropriate to assign a full load ratio share of transmission-related costs to behind the meter generation customers that do not use the network to the full extent of their load ratio shares.[916] Further, CAC/EPUC asserts that measuring the customer's use of the transmission system at the customer's meter would be appropriate as it would demonstrate that, if no power flows to the customer from the grid occur, that customer has not used nor caused costs to be incurred by the grid for the delivery of its energy requirements.

1617. Some commenters note that the Commission has approved PJM netting provisions that apply to behind the meter generation used by non-retail and wholesale customers to serve load.[917] These same commenters further observe that PJM has filed with the Commission to expand participation in its behind the meter generation netting program to include municipal, electric cooperatives, and electric distribution transmission customers who take network service on the PJM system pursuant to a settlement agreement filed by PJM on October 24, 2005 in Docket No. EL05–127–000.[918]

1618. Further, both TAPS and AMP-Ohio argue that behind the meter generation provides benefits to the transmission provider that should be taken into account as part of system planning obligations. For instance, AMP-Ohio asserts that utility planning can and should be able to take into account the ability of customers to reduce their load on the system with behind the meter generation. TDU Systems also notes PJM's representation that allowing municipal and electric cooperative system participation in behind the meter generation netting programs increased reliability and demand response opportunities on PJM's system.[919] Similarly, TAPS observes that PJM's rules reserve the right to call upon non-retail behind the meter generation under certain conditions.

Commission Determination

1619. The Commission is not persuaded to require transmission providers to allow netting of behind the meter generation against transmission service charges to the extent customers do not rely on the transmission system to meet their energy needs. Commenters in this proceeding have not provided any different arguments that were not fully considered and addressed in Order No. 888, *et al.* The existing *pro forma* OATT already permits transmission

[910] Order No. 888–A at 30,216.

[911] Order No. 888 at 31,736.

[912] Order No. 888–A at 30,258–61.

[913] *E.g.,* TAPS, TDU Systems, AMP-Ohio, and CAC/EPUC.

[914] TDU Systems and TAPS also cite *Consumers Energy*, 98 FERC ¶ 61,333 at 62,410 (2002) (requiring that a transmission provider's retail load associated with behind the meter generation be included in the transmission provider's load ratio share to ensure comparability between transmission providers and network customers in the calculation of load ratio share).

[915] *E.g.,* AMP-Ohio, CAC/EPUC, and TAPS.

[916] *Citing Occidental Chemical Corporation* v. *PJM Interconnection, L.L.C., and Delmarva Power & Light Company*, 102 FERC ¶ 61,275 at P 14 (2003) (''Access charges for use of PJM's transmission system should be allocated to network customers based on a network customer's actual use of PJM's system, consistent with the principle of cost-causation.''); *PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,113, at P 28 (2004).

[917] *E.g.,* AMP-Ohio, TAPS, and TDU Systems (*citing PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,113 (2004), *reh'g denied*, 108 FERC ¶ 61,032 (2004) (*PJM*)).

[918] This settlement agreement was accepted in *PJM Interconnection, L.L.C.*, 113 FERC ¶ 61,279 (2005).

[919] *PJM Interconnection, L.L.C.*, 113 FERC ¶ 63,024 (2005).

customers to exclude the *entirety* of a discrete load from network service and serve such load with the customer's behind the meter generation and through any needed point-to-point transmission service, thereby reducing the network customer's load ratio share. Therefore, the Commission's existing policy already provides customers with the opportunity to reduce network service costs to the extent a customer is not relying on the transmission system to meet its energy needs.[920] As the Commission concluded in Order No. 888–A, transmission customers ultimately must evaluate the financial advantages and risks and choose to use either network integration or firm point-to-point transmission service to serve load.[921] We believe it is most appropriate to continue to review alternative transmission provider proposals for behind the meter generation treatment on a case-by-case basis, as the Commission did in the PJM proceeding cited by the commenters.

8. Transmission Curtailments

1620. In the NOPR, the Commission proposed no changes to the *pro forma* OATT with respect to curtailment provisions for point-to-point service (set forth in sections 13.6 and 14.7) and network service (set forth in section 33). These provisions establish the terms and conditions under which a transmission provider may curtail service to maintain reliable operation of the system. Though several commenters claimed in response to the NOI that the reasons for transmission curtailments are difficult to discern, they did not provide sufficient detail to indicate whether that difficulty is a result of inadequate disclosure regulations, inadequate compliance with those regulations, or some other reason. Therefore, the Commission sought further comment on whether requiring transmission providers to post additional information would improve transparency and the ability of customers to make use of that information. The Commission also declined in the NOPR to propose generic penalties for improper transmission curtailments.

Comments

1621. APPA suggests that the Commission require transmission providers to produce additional information regarding firm transmission service curtailments, including all circumstances and events contributing to the need for such firm service curtailments, specific services and customers curtailed (including the transmission provider's own retail loads), and the duration of all such curtailments. TAPS also urges the Commission to move toward maximum transparency and require that sufficient information be provided for a customer to evaluate whether it has been treated fairly as compared to other users of the system including the transmission provider. TDU Systems suggests that the Commission require investigations into the need for network upgrades when Level 5 Transmission Loading Relief (TLR) procedures are repeatedly employed. It also suggests that all Level 5 TLRs be posted on OASIS and filed with the Commission. EEI agrees that providing customers with information on transmission curtailments may help to reduce confusion and suspicion concerning curtailments and suggests the Commission request WEQ (NAESB) to develop a more detailed template for posting information on curtailments that will be more useful to customers.

1622. Southern and other commenters[922] state that sufficient information regarding curtailments of transmission service is already available on OASIS and believe that the existing rules requiring transmission providers to make curtailment data available on OASIS are adequate. Nevada Companies request the Commission be very specific if it decides to mandate additional reporting requirements in order to remove the burden of potential confidentiality problems from the reporting entity.

1623. Powerex is concerned about inconsistent communication and curtailment procedures. It recommends that the Commission require three additional measures including: Early notice of curtailment through the use of the ''recall'' function on OASIS; a requirement to provide credits for curtailed service when non-firm point-to-point transmission service is interrupted; and requiring *pro rata* curtailments made prior to the energy scheduling and tagging deadline (*e.g.*, 20 minutes before the operating hour) to be based on reservation rather than schedule. In its reply comments, Seattle states support of *pro rata* curtailments based on reservations. TDU Systems recommend that the Commission require transmission providers to refund transmission charges to curtailed customers, to discourage transmission providers from overselling their systems. On reply, EEI and PNM–TNMP urge the Commission to reject the proposals to require transmission providers to refund transmission service charges to curtailed customers. They state that transmission providers are following ATC calculation procedures, but the planning process is not structured to overbuild the system to ensure that no curtailments occur. They also argue that the rate of return permitted in existing cost of service regulation does not account for the risk of loss of curtailment-related revenues. Northwest IOUs request the Commission examine whether *pro rata* curtailments of transactions to relieve transmission constraints unnecessarily impose burdens on transmission customers, because different curtailments on different paths have different effectiveness in relieving a given transmission constraint.

1624. Manitoba Hydro notes that MISO is the only RTO in the Eastern Interconnection that does not redispatch when constraints occur on non-market to market flows. Manitoba Hydro therefore urges the Commission to encourage implementation of redispatch to the fullest extent before resorting to curtailment. Seattle also supports modifying the *pro forma* OATT to require reliability redispatch. Seattle proposes that redispatch costs should be allocated to all classes of customers, and transmission providers' cost recovery should be allowed through automatic adjustment clause-type formulas to ensure all such costs are recovered. It suggests that routine maintenance outages are resulting in curtailments, which is an indication that transmission service is oversold. Seattle further suggests that transmission providers prepare a quarterly incident report for redispatch events detailing circumstances resulting in the redispatch, system status information, power transfer distribution factors, generator offers for redispatch and other information supporting redispatch determinations, including the basis for selecting generators called for redispatch.

1625. APPA, EEI and others comment that the Commission should not impose generic penalties for improper curtailments, but treat violations on a case-by-case basis. To ensure compliance with curtailment posting information, Southwestern Coop suggests that the Commission adopt generic penalties for curtailment violations, claiming that penalties for transmission provider curtailment discrimination would provide incentives for compliance.

[920] We note that EEI responds to allegations of undue discrimination in the calculation of load ratio share costs in the OATT Definitions section of this Final Rule.

[921] Order No. 888–A at 30,260–61.

[922] PNM–TNMP and TranServ.

Commission Determination

1626. The Commission concludes that the posting of additional curtailment information is necessary to provide transparency and allow customers to determine whether they have been treated in the same manner as other transmission system users, including customers of the transmission provider. A primary goal of this rulemaking is to remove opportunities for transmission providers to unduly discriminate in favor of their own or their affiliates' use of the transmission system. Making transparent details concerning transmission curtailments so that regulators and customers can verify that the transmission provider curtailed services in accordance with its OATT is entirely consistent with this goal. Commenters who oppose greater curtailment transparency offer no convincing evidence to suggest that any harm or hardship of doing so outweigh the benefits.

1627. We agree with suggestions for the posting of additional curtailment information on OASIS and, therefore, require transmission providers, working through NAESB, to develop a detailed template for the posting of additional information on OASIS regarding firm transmission curtailments. Transmission providers need not implement this new OASIS functionality and any related business practices until NAESB develops appropriate standards. These postings must include all circumstances and events contributing to the need for a firm service curtailment, specific services and customers curtailed (including the transmission provider's own retail loads), and the duration of the curtailment. This information is in addition to the Commission's existing requirements: (1) When any transmission is curtailed or interrupted, the transmission provider must post notice of the curtailment or interruption on OASIS, and the transmission provider must state on OASIS the reason why the transaction could not be continued or completed; (2) information to support any such curtailment or interruption, including the operating status of facilities involved in the constraint or interruption, must be maintained for three years and made available upon request to the curtailed or interrupted customer, the Commission's Staff, and any other person who requests it; and, (3) any offer to adjust the operation of the transmission provider's system to restore a curtailed or interrupted transaction must be posted and made available to all curtailed and interrupted transmission customers at the same time.

1628. The Commission rejects TDU Systems' proposal to require reports filed with the Commission regarding Level 5 TLRs or to require transmission providers to conduct investigations into the need for network upgrades when TLR 5 procedures are repeatedly employed. TDU Systems' proposal is unnecessary at this time in light of our requirement that OASIS templates for curtailment information be developed that will report occurrences of all levels of TLRs. This will enable the Commission and customers to monitor TLR patterns and frequency. Furthermore, the requirements imposed in this Final Rule for congestion studies as part of the coordinated, open and transparent planning requirement will allow stakeholders in the transmission provider's planning process to request studies of those portions of the transmission system where they have encountered transmission problems due to frequent and recurring constraints.

1629. The Commission rejects the three proposals suggested by Powerex. First, it is not necessary to provide early curtailment notification through the OASIS "recall" function since the OASIS currently provides a curtailment notification function. Transmission providers should continue to use the OASIS Schedule Details template to post information on the scheduled uses of the transmission system and any curtailments and interruption thereof. Second, with respect to Powerex's request to credit customers when their non-firm point-to-point transmission service is interrupted, we find it unnecessary to modify the *pro forma* OATT to adopt such crediting procedures, consistent with our finding in Order No. 888–A that proper crediting would vary depending on the specific rate design a company uses.[923] Third, we believe that pro-rating curtailments based on reservations would have the potential to impair reliability since the amount of capacity actually curtailed using this approach would not address actual power flows and, therefore, may be less than required to relieve the overloaded facility.

1630. The Commission also rejects TDU Systems' recommendation to refund transmission charges to curtailed customers as a means of disciplining instances of improper curtailments or transmission providers' overselling their systems. We also reject proposals to remedy improper curtailments through refunds of transmission charges to curtailed customers or imposing generic penalties. Rather, the Commission believes that addressing allegations of inappropriate curtailment practices or transmission providers overselling their transmission system are more effectively administered by the Commission on a case-by-case basis.

1631. With respect to the proposal to require redispatch to be performed to the fullest extent prior to curtailments, Manitoba Hydro itself notes that the proposal is intended to address curtailment and redispatch practices unique to MISO. Therefore we conclude that Manitoba Hydro's concerns are best addressed on a case specific basis.

1632. Regarding Seattle's proposal to require what it characterizes as "reliability redispatch" to benefit and be paid by all customer classes, we note that this proposal would require expansion of the network service "reliability redispatch" provisions to apply to point-to-point service as well. The network service "reliability redispatch" provisions in *pro forma* OATT sections 33.2 and 33.3 were established in Order No. 888 to ensure comparable reliable service to network customers as the service that the transmission provider provides to its bundled retail load. These redispatch procedures further provide for redispatch of not just the transmission provider's own resources, but all network resources, including those of network customers, when required to maintain the reliability of the system and avoid the need for curtailments. Seattle has not demonstrated that its proposal to extend "reliability redispatch" for point-to-point service is required to ensure comparable, not unduly discriminatory transmission service and has not addressed why network customer resources should be redispatched for the benefit of point-to-point customer. Accordingly, we decline to adopt Seattle's proposal. We discuss redispatch issues more broadly in section V.D.1 of this Final Rule.

[923] *See* Order No 888–A at 30,276. In *Allegheny Power System, Inc.*, 80 FERC ¶ 61,143 at 61,549 (1997), the Commission clarified that where a transmission provider has not proposed an express crediting provision for the interruption of non-firm point-to-point customers, the transmission provider must compute its bill to an interrupted non-firm customer as if the term of service actually rendered were the term of service reserved. In other words, if a customer with a weekly reservation was interrupted after one day, its bill must be computed as if it had a daily reservation, and if a customer with a daily reservation was interrupted after ten hours, its bill must be computed using the hourly rate applied to ten hours of service.

9. Standardization of Rules and Practices

a. Business Practices

1633. In Order No. 888, the Commission required each public utility that owns, controls, or operates facilities used for transmitting electricity in interstate commerce to file, pursuant to section 205 of the FPA, a *pro forma* OATT under which it would provide open access transmission services. However, certain rules, standards, and practices governing the provision of transmission service (*e.g.*, public utility business practices) are not reflected in the *pro forma* OATT. Only when a public utility adopts a rule, standard, or practice that significantly affects its rates and services has the Commission required it to make a filing pursuant to FPA section 205 to amend its OATT.[924] The Commission has applied this policy using a ''rule of reason'' test.[925]

NOPR Proposal

1634. In the NOPR, the Commission proposed not to modify its existing policy regarding the inclusion of rules, standards and practices in a transmission provider's OATTs. The Commission expressed concern that requiring transmission providers to include all of their rules, standards, and practices in their OATTs could decrease a transmission provider's flexibility to change business practices and respond to the requests of its customers. The Commission also expressed a belief that requiring transmission providers to file all of their rules, standards, and practices in their OATTs would be impractical and potentially administratively burdensome.

1635. The NOPR further noted that there is broad consensus that rules, standards, and practices not required to be included in a transmission provider's *pro forma* OATT should be posted on the transmission provider's OASIS. The Commission agreed and proposed to require transmission providers to post on OASIS all of their rules, standards, and practices that relate to transmission services. The Commission sought comment on how best to determine what ''relates'' to transmission service to facilitate a consistent interpretation and to minimize discretion on what rules, practice and standards should be posted on OASIS.

1636. On the particular issue of creditworthiness and security requirements, the Commission preliminarily concluded that the mere posting of information on OASIS was insufficient. The Commission proposed that each transmission provider's OATT contain sufficient information about its credit process and requirements to enable customers to understand the information required to demonstrate creditworthiness and to determine for themselves the general amount and type of security they may need to provide in order to receive service. The Commission therefore proposed to amend section 11 of the *pro forma* OATT on creditworthiness to require each transmission provider to include its creditworthiness and security requirements in a new Attachment L to its OATT. Consistent with the Creditworthiness Policy Statement,[926] the Commission proposed to require the new Attachment L to include such qualitative and quantitative criteria necessary to determine the level of secured and unsecured credit required, with supplementation in a credit guide or manual to be posted on OASIS.[927] The Commission sought comment on whether the proposal is unduly burdensome.

Comments

Included in Open Access Transmission Tariffs

1637. Many commenters express support for the continuation of the current Commission policy which requires the inclusion in the transmission provider's OATT of only those rules, standards and practices that significantly affect transmission rates and services.[928] These commenters generally state that any rule, practice, term or condition that could result in limiting access to transmission services, including rates and charges for service, should be included in the OATT and should be subject to Commission scrutiny. Examples given include all rules and practices affecting calculation of ATC, creditworthiness criteria, and rules or practices affecting the transmission provider's regional planning process. Commenters argue that Commission oversight is necessary to ensure that these rates, charges, rules, practices, terms or conditions of transmission service are reasonable and afford comparable treatment for wholesale customers.

1638. Other commenters advocate further inclusion of rules, standards and practices in the transmission provider's OATT. Morgan Stanley believes that business practices manuals should be incorporated into each OATT and filed with the Commission for approval. Morgan Stanley states that if this is not required then, at a minimum, each OATT should provide for a process to use when the transmission provider wishes to amend its business practices manuals. For example, transmission providers should provide notice to all affected parties of an intent to make a change, a mechanism to receive stakeholder feedback on the proposed change, and a minimum period of time between the final implementation decision and the effective date of the proposed change (*e.g.*, 30–60 days after final decision). Southwestern Coop, however, maintains that transmission providers should not be allowed to change their rules, standards and practices that affect the justness and reasonableness of OATTs without prior Commission review. Southwestern Coop states that the Commission should require all rules, standards and practices relating to transmission services to be included in the OATT filed with the Commission, because otherwise it cannot ensure that jurisdictional rates are just and reasonable.

Posted on OASIS

1639. Many commenters also express support for the proposed requirement that all rules, standards and practices that are not required to be included in a transmission provider's OATT and that affect a transmission provider's provision of transmission service be posted on OASIS.[929] Commenters generally state that these postings will allow for increased transparency, while affording the transmission provider flexibility to make revisions rather than

[924] *E.g.*, *Cleveland* v. *FERC*, 773 F.2d 1368, 1376 (D.C. Cir. 1985).

[925] *See, e.g.*, *Public Serv. Comm'n of N.Y.* v. *FERC*, 813 F.2d 448, 454 (D.C. Cir. 1987) (holding that the Commission properly excused utilities from filing policies or practices that dealt with only matters of ''practical insignificance'' to serving customers); *Midwest Independent Transmission System Operator, Inc.*, 98 FERC ¶ 61,137 at 61,401 (''It appears that the proposed Operating protocols could significantly affect certain rates and service and as such are required to be filed pursuant to section 205.''), *order granting clarification*, 100 FERC ¶ 61,262 (2002).

[926] *Policy Statement on Electric Creditworthiness*, 109 FERC ¶ 61,186 (2004) (Creditworthiness Policy Statement).

[927] The Commission proposed to require the new Attachment L to include the following elements: (1) A summary of the procedure for determining the level of secured and unsecured credit; (2) a list of the acceptable types of collateral/security; (3) a procedure for providing customers with reasonable notice of changes in credit levels and collateral requirements; (4) a procedure for providing customers, upon request, a written explanation for any change in credit levels or collateral requirements; (5) a reasonable opportunity to contest determinations of credit levels or collateral requirements; and (6) a reasonable opportunity to post additional collateral, including curing any non-creditworthy determination.

[928] *E.g.*, ISO/RTO Council, CAISO, LDWP, MISO/PJM States, PGP, and PNM–TNMP.

[929] *E.g.*, CAISO, EEI, MidAmerican, MISO/PJM States, Nevada Companies, PJM, Powerex, Santa Clara, Suez Energy NA, TDU Systems, and TAPS.

having to amend the OATT each time a change occurs.

1640. Powerex argues that the transmission provider also should be required to post data used to calculate ATC, any metrics the Commission adopts regarding the transmission provider's performance of system impact and facilities studies, information concerning both planned and unplanned transmission outages, and a transmission provider's business practices, tariff, organizational charts and job descriptions of its employees.

1641. Southern takes issue with the use in the NOPR of the phrase ''all of their rules, standards and practices,'' stating that language suggests that a transmission provider might be required to reduce each detail of its business practices to writing, which could be overly burdensome. In addition, Southern believes that any rule relating to posting requirements on OASIS should have certain mechanisms to allow the transmission provider to deviate from posted practices when necessary. In contrast, ELCON states that any rule, standard or practice used by the transmission provider and any of its employees to approve or disapprove a request for service should be committed to writing and posted. Similarly, TranServ argues that transmission providers should be required to post on OASIS any criteria applied by the transmission provider to any attribute of a transmission or ancillary service request for the purpose of determining whether the service request should be approved or denied.

1642. Northwest IOUs suggests that the Commission should adopt a ''rule of reason'' test for matters required to be posted on the OASIS similar to the test applied to matters required to be included in the OATT.

Creditworthiness

1643. Several commenters support the inclusion of a separate Attachment L to the *pro forma* OATT outlining creditworthiness requirements, asserting that Attachment L will standardize credit procedures and security requirements and increase transparency.[930] Suez Energy NA states that the proposal is not unduly burdensome, that the procedures proposed are not different from the Creditworthiness Policy Statement or the procedures already imposed in individual cases, and that the Commission is merely proposing to apply an existing requirement in a non-discriminatory manner.

1644. Other commenters propose modifications to the credit-related proposals set forth in the NOPR. TAPS urges the Commission to require the transmission provider to adopt a two-part creditworthiness assessment in order to facilitate non-burdensome and fair assessment of creditworthiness. TAPS recommends that a standard similar to the Florida Power Corp. OATT be applied, which provides that customers with ''satisfactory long-term payment history'' and a minimum credit rating of Baa2 (Moody's) or BBB (S&P) would not have to post any credit security. If a customer fails to meet the threshold test, TAPS states that the transmission provider would perform a transparent credit assessment that is consistent with the Commission's Creditworthiness Policy Statement and the credit policies developed for use in regional transmission organizations such as MISO and SPP. According to TAPS, since quantitative measures sometimes understate public power creditworthiness, transmission providers will need to weigh qualitative factors more heavily than quantitative factors in assessing public power creditworthiness. For public entities that fail the threshold test, TAPS states that transmission providers should use outstanding bond indebtedness as a proxy for tangible net worth for those entities whose energy and transmission service payments receive priority over bond payments.

1645. PJM generally agrees with the creditworthiness proposals, except for inclusion in the OATT of the actual detailed algorithms used to calculate credit scores, stating that those algorithms, as the Commission recognized,[931] may change over time. In PJM's view, requiring all such changes to be approved by the Commission would be unnecessarily burdensome to both the Commission and the transmission provider. PJM recommends that the overall framework of the credit determinations be included in the OATT, while the detailed algorithms be posted on OASIS to meet transparency goals. PJM also recommends that the Commission accept, as an option, a regularly-updated posting on the transmission provider's Web site of each customer's available credit and collateral requirement as sufficient notification for most changes in credit available and credit requirements. PJM further recommends that only significant and sudden reductions in credit available (for example, those greater than 25 percent within a one-month period) be subject to an active notification requirement.

1646. TVA recommends the Commission consider two fundamental principles as it standardizes creditworthiness terms and conditions. First, as long as qualitative factors are part of the equation (and TVA agrees that they should be), TVA states that certain subjective judgments by the transmission provider will be required. TVA encourages the Commission to provide guidance on appropriate criteria to consider in making these judgments, but not to remove entirely from the process the flexibility necessary for individual assessments of customer creditworthiness. Second, TVA states that transmission providers may have to impose different security requirements as a result of differences in statutes, regulations, or other legal requirements. For example, TVA states that its ability to incur debt is limited by section 15d(a) of the Tennessee Valley Authority Act[932] and, therefore, it may need to impose security requirements that are stricter than those of a public utility, as the Commission has previously recognized.[933] TVA requests that the final rule respect these differing legal obligations and provide corresponding flexibility in credit decisions among transmission providers.

1647. A number of commenters oppose the Commission's proposed creditworthiness policy.[934] In general, these commenters believe that each transmission provider should have the flexibility to make and change creditworthiness procedures without the delay of obtaining Commission approval. They also argue that the Commission's goal of transparency could be better achieved by requiring the posting of a transmission provider's creditworthiness policy on OASIS.[935] Xcel and MidAmerican assert that the Commission's proposal would decrease a transmission provider's ability to timely respond to changing market and financial conditions and, therefore, creditworthiness and security requirements should simply be posted on OASIS. Southern believes that the Commission should permit but not require transmission providers to file their creditworthiness and security procedures as part of their OATTs.[936]

[930] *E.g.*, APPA, East Texas Cooperatives, Lassen, MISO/PJM States, Nevada Companies, NRECA, PGP, Powerex, Southern, Suez Energy NA, TANC, and TAPS.

[931] *See* NOPR at P 456.

[932] 16 U.S.C. 831n–4.

[933] *Citing East Ky. Power Coop., Inc.*, 114 FERC ¶ 61,035 at P 56 (2006).

[934] *E.g.*, MidAmerican, Southern, PNM–TNMP, NorthWestern, and Xcel.

[935] *E.g.*, PNM–TNMP, EEI, and MidAmerican.

[936] Southern states that it already includes creditworthiness and security requirements in its

Southern also asks that the Commission allow a transmission provider, in its compliance filing, to request a determination that its current creditworthiness policies and practices are acceptable under the new Commission policies. Similarly, ISO-New England states that this rulemaking should not modify the ISO-New England Financial Assurance and Billing Policies, which are already on file with the Commission.

1648. CAISO states that although the NOPR requirements concerning credit and security requirements do not appear unduly burdensome, it is concerned that the Commission may apply these requirements in a manner that will impose an undue burden on transmission providers and effectively eliminate the ability of transmission providers to supplement basic elements with a credit guide or manual. CAISO and MidAmerican further state that there is no legitimate reason to treat credit policies and procedures any differently than the other rules, practices and standards that the Commission permits to be included on OASIS and does not require to be filed as part of the tariff. Santa Clara recommends that if the Commission decides to require creditworthiness and security policies to be posted on OASIS rather than included in the OATT, then it should require at least a 30-day notice period for changes in the credit policies.

Commission Determination

1649. The Commission adopts the NOPR proposal to continue to require only those rules, standards, and practices that significantly affect transmission service be incorporated into a transmission provider's OATT. The Commission further affirms the use of a ''rule of reason'' to determine what rules, standards, and practices significantly affect transmission service and, as a result, must be included in the transmission provider's OATT.

1650. The ''rule of reason'' test has arisen primarily with respect to protocols or operating procedures used by RTOs and ISOs. For example, the Commission has held that, while MISO's business practices manuals implicate the Commission's jurisdiction because they generally involve ''the installation, operation, or use of facilities for the transmission or delivery of power in interstate commerce,'' they do not require an FPA section 205 filing because ''they mostly involve general operating procedures.'' In other cases, the facts have required the filing of the rule, standard or practice. For example, CAISO proposed to post certain technical, operational and business standards related to dynamic scheduling on its Web site and include only the rates under its OATT. In that instance, the Commission found that the details contained in the standards were practices that could significantly affect the terms and conditions of service and, therefore, under the Commission's ''rule of reason'' must be filed under section 205 of the FPA.[937]

1651. Comments received in response to the NOPR confirm that there is broad support for the Commission's existing practice, requiring only those rules, standards, and practices that significantly affect transmission service, and the use of the ''rule of reason'' test to identify those rules, standards, and practices. The Commission disagrees with parties arguing that all of a transmission provider's rules, standards, and practices should be incorporated into its OATT. We believe that requiring transmission providers to file all of their rules, standards and practices in their OATTs would be impractical and potentially administratively burdensome.

1652. The Commission instead requires transmission providers to post on their public Web sites all rules, standards, and practices that relate to transmission service and provide a link to those rules, standards, and practices on OASIS. We conclude that it would not be appropriate to place the rules, standards, and practices only on OASIS as some transmission providers use certificates to restrict access to their OASIS sites. By providing a link on OASIS to the rules, standards, and practices that are otherwise publicly posted, the Commission ensures that all potential customers will have access to the information necessary for them to understand the terms and conditions of service. We amend section 4 of the *pro forma* OATT to expressly establish this posting requirement.

1653. We note that we already require certain rules and practices to be posted on OASIS.[938] We find that it is now necessary to also require that all rules, standards or business practices that relate to the terms and conditions of transmission service, and how that transmission service is provided to customers, to be detailed, clearly stated on the transmission provider's public Web site, with a link to this information on OASIS.[939] We emphasize that this requirement applies to all such rules, standards, and practices, currently written or otherwise.[940] While we acknowledge this requirement will result in some burden to transmission providers, we find that this approach is necessary to provide greater transparency and mitigate the potential for undue discrimination against customers taking service under the transmission provider's OATT. Further, our holding is not intended to eliminate all discretion under the *pro forma* OATT; rather, we recognize that certain tariff provisions require consideration of the specific facts and circumstances related to particular service requests.[941] We merely require that, if the transmission provider uses standards, rules or business practices to administer its OATT, such standards, rules or business practices must be available for public inspection. Moreover, we note that our actions here are consistent with actions we have taken in recent proceedings. For example, the Commission has required that certain business practices manuals be posted

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OATT since the Commission issued its Creditworthiness Policy Statement.

[937] *California Independent System Operator Corp.*, 107 FERC ¶ 61,329 at P 21–22 (2004); *see also Southwest Power Pool, Inc.*, 112 FERC ¶ 61,303 at P 25 (requiring that the SPP OATT provide sufficient information for market participants to fully understand SPP's implementation of an imbalance market), *reh'g denied*, 113 FERC ¶ 61,115 (2005); *PJM Interconnection, L.L.C.*, 104 FERC ¶ 61,124 at P 61 (requiring PJM to place all procedures, standards and requirements for proposing that a transmission owner construct a specific upgrade, and all procedures for charging customers, in its tariff, not in its manuals), *order on reh'g, PJM Interconnection, L.L.C.*, 105 FERC ¶ 61,123 (2003).

[938] *See, e.g.*, Order No. 889 at 31,588–89; *Open Access Same-Time Information Systems*, Order No. 605, 64 FR 34117 (Jun. 25, 1999), FERC Stats. and Regs. ¶ 31,075 (1999); Order No. 676 at P 79.

[939] If a particular rule, standard or practice conflicts with an OATT provision, the OATT of course shall govern in all circumstances. Moreover, as noted in the NOPR, we emphasize that posting rules, practices and standards—in lieu of filing such practices with the Commission as part of the transmission provider's *pro forma* OATT—neither insulates a transmission provider from complaints nor confers a just and reasonable presumption. We encourage customers to call the Commission's Enforcement Hotline with complaints about the application of such rules, standards and practices should they experience problems with their transmission providers. To the extent customers are not satisfied with responses from their transmission provider, they should contact the Commission's Enforcement Hotline via telephone (202) 502–8390, toll-free 1–888–889–8030, fax (202) 208–0057, or at *http://www.ferc.gov/cust-protect/enforce-hot.asp.*

[940] With respect to the business practices developed by NAESB, there may be certain copyright restrictions that limit the transmission provider's ability to post those practices on its own Web site. In such instances, we expect that the transmission provider will reference any NAESB practices it uses and provide a link on its public Web site to the NAESB Web site in order to provide interested parties with a means to access the copyrighted material.

[941] The circumstances and manner in which a transmission provider exercises its discretion under its OATT must be posted in accordance with 18 CFR 37.6(4).

and made available for public view on a permanent basis.[942] As in those cases, we find that making rules, standards, and practices readily accessible will serve as a tool to supplement each transmission provider's OATT and facilitate fair and open access to the transmission grid.

1654. To provide guidance to the transmission providers as to whether a particular rule, standard, or practice ''relates to'' transmission service, and therefore warrants posting, the Commission believes the MAPP Policies and Procedures for Transmission Operations manual is a good example of the type of information that relates to the terms and conditions of transmission service. For example, the MAPP manual sets forth information supplementing its OATT pertaining to (1) transmission service requests on the MAPP OASIS site, (2) the retraction of an accepted or counteroffer transmission request, (3) timing requirements for transmission service requests, (4) methods to accommodate a firm transmission request with redispatch, and (5) transmission service charge implementation procedures. Other examples include detailed information regarding tagging, scheduling, billing and other matters provided in other RTO manuals. This is the type of information that clearly relates to transmission service and therefore must be reduced to writing and publicly posted.

1655. We also agree with requests to require a transparent process for amending rules, standards, and practices previously posted by a transmission provider. We therefore require each transmission provider also post on its public Web site (with a corresponding link on OASIS) a statement of the process by which the transmission provider will amend these rules, standards, and practices that are accessible via OASIS. As part of this process, the transmission provider must specify a mechanism to provide reasonable notice of any proposed changes to a posted business practice and the respective effective date of such change.[943] We amend section 4 of the *pro forma* OATT to formalize this posting requirement and obligate transmission providers to follow the amendment procedures specified by the transmission provider. As with the requirement to post the underlying standards, rules and practices, we believe the amendment procedures required here will increase transparency and help minimize opportunities for undue discrimination.

1656. The Commission also adopts the NOPR proposal and amend the *pro forma* OATT to include a new Attachment L.[944] We find that the transmission provider's basic credit standards significantly affect transmission service and, therefore, must be included in the *pro forma* OATT. This will ensure that all customers have clear information as to the credit process and standards used by a transmission provider to grant or deny transmission service and, in turn, will serve to prevent undue discrimination and eliminate a potentially significant barrier to entry in the provision of service. Most importantly, by making Attachment L a part of the *pro forma* OATT, customers will have an opportunity to comment on any changes to the standards proposed by a transmission provider in a rate filing with the Commission.

1657. To that end, each transmission provider's Attachment L must specify the qualitative and quantitative criteria that the transmission provider uses to determine the level of secured and unsecured credit required. Attachment L must also contain the following elements: (1) A summary of the procedure for determining the level of secured and unsecured credit; (2) a list of the acceptable types of collateral/security; (3) a procedure for providing customers with reasonable notice of changes in credit levels and collateral requirements; (4) a procedure for providing customers, upon request, a written explanation for any change in credit levels or collateral requirements; (5) a reasonable opportunity to contest determinations of credit levels or collateral requirements; and (6) a reasonable opportunity to post additional collateral, including curing any non-creditworthy determination. We will allow the transmission provider to supplement Attachment L with a credit guide or manual to be posted on OASIS.

1658. We disagree with commenters that claim requiring this information in an attachment to each transmission provider's OATT will hinder the transmission provider's ability to timely respond to changing market and financial conditions. Because Attachment L requires only a summary of credit requirements and other information, we expect the need to revise Attachment L will occur infrequently. As suggested by PJM, detailed information, such as the algorithms used by the transmission provider to determine credit scores, can be posted on OASIS along with other information that relates to the provision of transmission service. Thus, the requirement we are imposing should not be overly burdensome.

1659. At the same time, we agree that transmission providers need flexibility in determining credit requirements in light of qualitative and quantitative factors, as we recognized in the NOPR and the Creditworthiness Policy Statement. We believe the requirements adopted in this Final Rule allow for such flexibility. By requiring transmission providers to consider both quantitative and qualitative factors, the particular circumstances surrounding public power entities can be recognized. We agree, moreover, with TVA that the transmission provider's credit policies must be consistent with its legal obligations and expect that interested parties will bring any legal conflicts to our attention on review of the transmission provider's compliance filing.

1660. With regard to requests to find existing credit policies consistent with the requirements of the Final Rule, all transmission providers will be required to demonstrate compliance with all aspects of the Final Rule either by implementing the reforms adopted today or showing that departures are consistent with or superior to the terms and conditions of the *pro forma* OATT, as modified by this Final Rule. The procedural mechanisms for making such a showing provided for in section IV.C above give transmission providers the opportunity to demonstrate that retention of their existing credit practices is appropriate.

1661. Finally, with regard to Santa Clara's request to require the transmission provider to provide at least a 30-day notice period for changes in creditworthiness and security policies that are posted on OASIS, we explain above that each transmission provider must identify and incorporate a specific process in its OATT for amending business practices that are posted on OASIS. Such practices include those

[942] *See, e.g.*, *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,163 at P 658, *order on reh'g*, 109 FERC ¶ 61,157 (2004), *order on reh'g*, 111 FERC ¶ 61,043, *order on reh'g*, 112 FERC ¶ 61,086 (2005); *see also PJM Interconnection, L.L.C.*, 81 FERC ¶ 61,257 at 62,267 (1997) (finding no reason to require filing of the PJM Manuals but requiring that such manuals be available for public inspection on a permanent basis), *order on reh'g*, 92 FERC ¶ 61,282 (2000).

[943] As part of their business practice amendment procedures, transmission providers may adopt such additional procedures they deem appropriate, such as opportunities for comment to proposed changes to rules, standards, and practices.

[944] As with new Attachment K to the *pro forma* OATT, regarding transmission planning, we acknowledge that some transmission providers may already have attachments to their OATTs labeled with the letter ''L,'' in which case transmission providers are free to label their credit procedures OATT attachment with the next available letter.

that describe and implement its creditworthiness and security policies.

b. Liability and Indemnification

1662. In Order No. 888, the only liability provisions included in the *pro forma* OATT related to force majeure and indemnification.[945] Section 10.1 of the *pro forma* OATT provides that neither the transmission provider nor the transmission customer will be considered in default as to any obligation under the tariff if prevented from fulfilling the obligation due to an event of force majeure. A party whose performance under the tariff is hindered by an event of force majeure, however, is required to make all reasonable efforts to perform its obligations under the tariff. With respect to indemnification, under section 10.2 of the *pro forma* OATT, the transmission customer indemnifies the transmission provider against third party claims arising from the transmission provider's performance of its obligations under tariff on behalf of the transmission customer, except in cases of negligence or intentional wrongdoing by the transmission provider.

(1) Force Majeure

Comments

1663. Santa Clara queries whether the Commission intended to make the transmission provider's performance of its obligations less burdensome by using the phrase ''all reasonable efforts'' instead of ''due diligence'' in the force majeure provision in section 10.1 of the *pro forma* OATT is. In either case, Santa Clara requests the Commission to consider the use of the most stringent term when addressing a transmission provider's obligation to perform under its tariff.

Commission Determination

1664. The Final Rule retains the current ''all reasonable efforts'' standard in the force majeure provision. Santa Clara does not explain how the ''all reasonable efforts'' standard may be more or less stringent than the ''due diligence'' standard. Further, as the Commission explained in Order No. 888, this protection against unexpected and unpredictable events is appropriately made available to both the transmission provider and transmission customer. We therefore find that the clarification requested by Santa Clara is unnecessary.

[945] Order No. 888–B at 62,081

(2) Indemnification/Limitation of Liability

Comments

1665. Several commenters[946] urge the Commission to change the indemnification provision to protect transmission providers from liability except in the case of gross negligence or intentional misconduct, thereby exempting the transmission provider from liability for acts of ordinary negligence. These commenters also request that the Commission add to the *pro forma* OATT a new provision clarifying that the transmission provider would not be liable to any transmission customer or third party for direct, incidental, consequential, indirect, or punitive damages arising from services provided under the tariff, except in cases of gross negligence or intentional misconduct (in which case, EEI, and Northwest IOUs propose, liability would be limited to direct damages). These commenters note that the Commission has allowed transmission providers this protection in the tariffs of MISO, PJM, ISO New England, SPP, and their member transmission owners and generators, but it has not fully explained its basis for treating non-RTO member transmission providers differently from RTOs and ISOs. EEI further notes that the Commission accepted similar liability protection in the Large Generator Interconnection Agreement (''LGIA'') and in natural gas pipeline tariffs.[947] EEI requests that this liability limitation be added to the *pro forma* transmission service agreement that would apply to transmission customers acting in good faith to carry out the directives of a transmission provider.

1666. With respect to third party indemnification, EEI notes that the Commission reasoned in SPP that, even though a broader liability limitation would relieve a transmission provider from liability for ordinary negligence, that provision only applies to transmission customers under the tariff. EEI states that there are many other entities that could initiate legal action against the transmission provider in connection with the provision of transmission service, thereby making an adequate indemnification provision in the *pro forma* OATT necessary for the same reasons as the limited liability provision.[948]

[946] *E.g.*, Southern, EEI, and Northwest IOUs.

[947] *Citing* Article 18, Large Generator Interconnection Agreement; *ANR Pipeline Co.*, 98 FERC ¶ 61,218, *order on tariff filing*, 100 FERC ¶ 61,132 (2002).

[948] *Citing Southwest Power Pool, Inc.*, 112 FERC ¶ 61,100 at P 39 (2005).

1667. EEI contends that the addition of the Commission's new EPAct 2005 authority to establish mandatory reliability standards to provide open access transmission service to all customers, regardless of their risk profile, makes it an appropriate time to revisit the liability provisions in the OATT. According to EEI, a limitation on liability in the *pro forma* OATT should be viewed as a necessary element of the implementation of the Commission's reliability authority. Because transmission providers cannot deny service to particular customers based on the risk of potential damages, EEI and Southern assert that all transmission providers should be protected from certain risks associated with this obligation to serve. EEI argues that increased protection from liability would lower the cost of capital for new transmission projects and promote the expansion of transmission infrastructure. EEI further argues that the technological complexity of modern utility systems and the potential for service interruptions unrelated to human errors justify liability limitations. According to EEI, a limitation on liability to direct damages puts the risk on those customers with special reliability needs, rather than spreading the risk among all customers.

1668. EEI notes that the Commission has denied requests for exemptions from liability for ordinary negligence in the indemnification provision on the grounds that liability and indemnification were ''separate issue[s]'' and that transmission providers seeking liability protections could rely on state laws.[949] EEI argues, however, that an OATT and the accompanying service agreement constitute a contract between the transmission provider and the customer that is established pursuant to federal law and, as a result, it is not at all clear that a state law limitation on liability would apply. Southern asserts that adopting liability limits would provide uniformity, certainty, and reduce risk since reliance on state law is an issue not free from doubt.

1669. Entegra argues on reply that the NOPR did not contemplate any modification to these provisions of the *pro forma* OATT and neither EEI nor Southern has established a nexus between such a modification and the goals set forth in the NOPR. TDU Systems on reply similarly argue that EEI's request is outside the scope of the rulemaking and neither EEI nor Southern show a change in circumstance justifying a new limitation

[949] *Citing* Order No. 888–A at 30,301.

on liability. Immunizing transmission providers from these liability risks, TDU Systems contend, would simply transfer risk to customers that have no control over the transmission provider's negligence. Entegra and TDU Systems further argue that Southern previously sought the same relief in a tariff filing rejected by the Commission less than a year ago, stating that the Commission thus already rejected the notion that Southern was similarly situated to the RTOs and ISOs that have this protection.[950] Entegra notes that Southern did not seek rehearing of that order and its comments here are therefore an impermissible collateral attack on a final Commission order. As for the argument regarding EPAct 2005, TDU Systems note that the Commission presumably was aware of its new reliability authorities when it issued the *Southern* order four months after EPAct was enacted.

1670. TDU Systems also point out that the tariff language proposed by EEI would not protect a transmission customer from being sued by a third party for the negligence or willful misconduct of the transmission provider. In such lawsuits, TDU Systems claim, a third party would not be limited to direct damages. According to TDU systems, any indemnification as between the transmission provider and the transmission customer that is limited to direct damages would leave the customer holding the bag for the indirect damages caused by the transmission provider's negligence or willful misconduct.

Commission Determination

1671. We will retain the current liability protections in the *pro forma* OATT for the same reasons that the Commission has rejected similar past proposals. While the Commission explained in Order Nos. 888–A and 888–B that the *pro forma* tariff was not intended to address liability issues, as EEI notes, the Commission stated that liability was a separate issue from indemnification.[951] The Commission further explained that transmission providers were not precluded from relying on state laws that protected utilities or others from claims founded in ordinary negligence.[952] The Commission declined to adopt a uniform federal liability standard and decided that, while it was appropriate to protect the transmission provider through force majeure and indemnification provisions from damages or liability when service is provided by the transmission provider without negligence, it would leave the determination of liability in other instances to other proceedings.[953]

1672. On the issue of a negligence standard for the indemnification provision, we decline to depart from our policy set forth in Order No. 888, as affirmed in Order No. 888–A and subsequent orders.[954] In Order No. 888, the Commission stated:

> We have limited the indemnification portion of the provision so that it is now only the transmission customer who indemnifies the transmission provider from the claims of third parties. The customer is taking service from the transmission provider and may appropriately be asked to bear the risks of third-party suits arising from the provision of service to the customer under the tariff. We find that this new indemnification provision would be too strict if it required customers to indemnify transmission providers even in cases where the transmission provider is negligent. Accordingly, the revised provision provides that the customer will not be required to indemnify the transmission provider in the case of negligence or intentional wrongdoing by the transmission provider.[955]

1673. The Commission subsequently addressed this issue in *Northeast Utilities.* There, the Commission found that a broader customer indemnification obligation that would include ordinary negligence would not give any incentive to the transmission provider to avoid negligent actions. In *Northeast Utilities,* the Commission explained again why it permitted a gross negligence exception in the *pro forma* LGIA section 18.1 in order to further limit the transmission provider's liability. As the Commission explained in Order No. 2003, interconnection warrants a different standard because it presents a greater risk of liability than exists for the provision of transmission service. The Commission further found that because risk exposure can increase interconnection costs, a broader indemnity standard is appropriate in the interconnection context.[956]

1674. Further, unlike Order No. 888 in which the transmission customer indemnifies the transmission provider, in Order No. 2003 the indemnity provision is expressly bilateral. In Order No. 2003 the interconnecting generator and the transmission provider each indemnifies the other from all damages to third parties arising under the LGIA from conduct on behalf of the indemnifying party, except in cases of gross negligence. Given that the indemnification provision in the *pro forma* LGIA is bilateral, in contrast to the *pro forma* OATT, it is reasonable to permit a gross negligence standard in the case of an interconnection.

1675. We also reject commenters' assertions that the liability standard the Commission has approved for RTOs/ISOs and gas pipelines is appropriate for other transmission providers. In the Reliability Policy Statement,[957] the Commission stated that it would consider, on a case-by-case basis, proposals by public utilities to amend their OATTs to include limitations on liability. The Commission further noted that while this issue has not been resolved on a standardized basis, the Commission has entertained RTO transmission providers' specific proposals to amend their OATTs to include provisions addressing limitations on liability.[958]

1676. In subsequent orders, the Commission found that the gross negligence and intentional wrongdoing indemnification and liability standard is appropriate for RTOs and ISOs. However, the Commission has declined to extend this protection to all transmission providers. In *Southwest Power Pool, Inc.*, the Commission explicitly stated ''that our acceptance here of the gross negligence and intentional wrongdoing indemnity standard is limited to SPP, in its role as an RTO, and its TOs; we do not intend to extend such protection to all transmission providers.'' [959] In *Southern Company Services, Inc.*, the Commission stated that:

> Having considered Southern Companies' proposed limitation on liability and indemnification provisions pursuant to our Reliability Policy Statement cited above, we find that Southern Companies have not shown that they are similarly situated to the RTOs/ISOs they cite in support. While Southern Companies claim that they ''may not be protected by any State-regulated limitations on liability,'' Southern Companies offer no evidence to support this concern. The Commission has provided such liability protection to RTOs/ISOs because they were created by and solely regulated by the Commission, and otherwise would be without limitations on liability. Southern Companies have proffered no evidence of any

[950] *See* Entegra Reply (*citing Southern Company Services, Inc.*, 113 FERC ¶61,239 (2005)).

[951] *See* Order No. 888–A at 30,301 and Order No. 888–B at 62,081 (section 10.2 of the *pro forma* OATT).

[952] Order No. 888–A at 30,301.

[953] Order No. 888–B at 62,081.

[954] *See, e.g.*, *Northeast Utilities Services Co.*, 111 FERC ¶ 61,333 (2005) (Northeast Utilities).

[955] Order No. 888 at 31,765.

[956] Order No. 2003 at P 636; Order No. 2003–A at 31,162.

[957] *Policy Statement on Matters Related to Bulk Power System Reliability*, 107 FERC ¶ 61,052 (2004) (Reliability Policy Statement).

[958] Reliability Policy Statement at P 40 (citations omitted).

[959] 112 FERC ¶ 61,100 at P 39 (2005).

change in circumstances vis-à-vis their liability exposure post-Order No. 888.[960]

1677. Commenters offer no new arguments that demonstrate that they are unable to rely on state laws, *i.e.*, the state laws provide inadequate protection. While EEI and Southern assert that there is uncertainty in whether state law on liability would apply to a service agreement between a transmission provider and a transmission customer, we note that neither provide any evidence that transmission providers are actually precluded from relying on state law for liability protection. EEI and Southern thus fail to show that the potential for a legal and regulatory gap is so great as to warrant inclusion of liability protections in the *pro forma* OATT for all transmission providers. In this regard, the Commission also finds without merit assertions that increased liability protections in the *pro forma* OATT should be viewed as a necessary element of the implementation of the Commission's reliability authority. As none of the arguments proffered by commenters persuade us to change our policy regarding liability protections applicable to non-RTO and non-ISO transmission providers, we decline to modify the liability protections in the *pro forma* OATT.

10. OATT Definitions

1678. In order to support the reforms adopted in this Final Rule and otherwise clarify the requirements of the *pro forma* OATT, the Commission adds and amends various definitions in the *pro forma* OATT, as set forth below.

a. Affiliate

NOPR Proposal

1679. In the NOPR, the Commission proposed a new definition of Affiliate incident to the proposed change to the pricing of reassigned capacity.

Comments

1680. Some commenters request clarification that the proposed definition of Affiliate would not apply to transmission-only cooperatives or independent entities such as RTOs. NRECA asserts that in Order No. 2004–A, the Commission concluded that ''[g]eneration and transmission cooperatives (G&T) are not subject to the Standards of Conduct consistent with the policies established under Order No. 888.'' NRECA asks for confirmation that distribution and generation and transmission cooperatives will not be considered affiliates of each other for OATT and Standards of Conduct purposes because recent pleadings reveal that there continues to be confusion about this definition. TranServ asks for clarification of the application of the definition of ''affiliate'' with respect to a merchant affiliate of a transmission provider that has turned over tariff administration functions to an ISO, RTO, or other independent entity. PNM–TNMP suggests that the definition of Affiliate be expanded or clarified to encompass divisions of an entity that operate as a functional unit. PNM–TNMP asserts that such a change would make clear that an Affiliate includes not only separate legal entities, but also may apply to divisions and functional units within the entity.

Commission Determination

1681. As discussed in section V.C.4, the Commission lifts the price cap on reassigned transmission capacity for all transmission customers, regardless of affiliation with the transmission provider. It is therefore no longer necessary to define an affiliate for purposes of that provision. The Commission nonetheless adopts the proposed definition of Affiliate to implement the reforms associated with distribution of operational penalties discussed in section V.C.5.b.

1682. With regard to the request that we clarify that an Affiliate does not apply to transmission-only cooperatives, we agree with NRECA that the Commission made clear in Order No. 888–A that there was no corporate affiliation between G&T cooperatives and their member distribution cooperatives.[961]

1683. TranServ requests clarification regarding the use of the term ''affiliate'' in the context of a transmission owner that has turned over operational control of its transmission facilities to an RTO, ISO, or to an independent entity. We clarify that, for purposes of the distribution of penalties, if such transmission owner is not required to be a transmission provider under a Commission-approved tariff, the merchant affiliate of such transmission owner would not be considered to be an ''affiliate'' of the RTO, ISO, or independent entity under the definition adopted in this Final Rule. The affiliation of a merchant to a transmission owner does not establish an affiliation between such merchant and the RTO, ISO, or independent entity transmission provider.

1684. As to PNM–TNMP's request that the definition of ''affiliate'' be expanded or clarified to encompass divisions of an entity that operate as a functional unit, we note that PNM–TNMP's concern appears to have been raised in the context of lifting the price cap for capacity reassignment, initially proposed only for non–affiliated transmission customers. We believe we have addressed PNM–TNMP's concerns by lifting the price cap for capacity reassignment for all customers, including affiliates of the transmission provider and the transmission provider's merchant function.

b. Good Utility Practice

NOPR Proposal

1685. In the NOPR, the Commission proposed to incorporate the definition of reliable operation from FPA section 215 in the definition of Good Utility Practice in the *pro forma* OATT.

Comments

1686. No commenters oppose the Commission's proposal to modify the definition of Good Utility Practice to reference the reliable operation standard of FPA section 215.

Commission Determination

1687. The Commission adopts the NOPR proposal to incorporate the definition of reliable operation from FPA section 215 in the definition of Good Utility Practice in the *pro forma* OATT. FPA section 215(b) obligates all users, owners and operators of the bulk power system to comply with reliability standards that will take effect under that section. Referencing section 215 in the definition of Good Utility Practice is appropriate to ensure that the reliability standards ultimately developed by the ERO and approved by the Commission are reflected in the *pro forma* OATT.

c. Non-Firm Sales

NOPR Proposal

1688. The Commission proposed to add a definition for Non-Firm Sales to clarify the treatment of such sales under section 30.4 of the *pro forma* OATT.[962] The Commission proposed defining a Non-Firm Sale as ''an energy sale for which delivery or receipt of the energy may be interrupted for any reason or for no reason, without liability on the part of either the buyer or seller.'' The Commission also proposed to clarify that, for the purposes of applying

[960] 113 FERC ¶ 61,239 at P 7 (2005).

[961] Order No. 888–A at 30,286 and 30,366.

[962] Section 30.4 as proposed in the NOPR provides, in relevant part, that ''[t]he Network Customer shall not operate its designated Network Resources located in the Network Customer's or the Transmission Customer's Control Area such that the output of those facilities exceeds its designated Network Load, plus Non-Firm Sales delivered pursuant to Part II of the Tariff, plus losses.''

section 30.4, energy sales that can only be interrupted to maintain system reliability would be considered firm sales.

Comments

1689. Several commenters argue that the proposed definition of Non-Firm Sales could impede a network customer's ability to obtain transmission service for certain types of energy products. In particular, Duke, EEI, and Southern question the treatment of power purchase agreements with LD provisions under the proposed definition. Duke contends that a contract with an LD provision might be interruptible for any reason, but it would still provide for liability in the form of LD payments. As a result, the LD contract might not fall within the definition of a Non-Firm Sale. At the same time, network customers can only designate resources from system purchases not linked to a specific generating unit if the purchase power agreement is not interruptible for economic reasons, does not excuse seller performance for economic reasons, and requires the network customer to pay for the purchase.

1690. Commenters are thus concerned that some contracts with LD provisions may be too firm to be a Non-Firm Sale, but not firm enough to be designated as a network resource. Duke argues that network customers should be allowed to operate their Network Resources to both serve load and sell a firm LD product. EEI is concerned that the proposed definition of Non-Firm Sales would prohibit a network customer from making an off-system sale of a firm LD product or any other product that does not result in undesignation of a Network Resource, given the restrictions set forth in section 30.4. Duke and EEI therefore propose that a Non-Firm Sale should be defined as any sale that is not sufficiently firm to be designated a Network Resource of the purchasing entity. Raising concerns similar to those raised by Duke and EEI, Southern proposes to define Non-Firm Sales as any sale that does not commit the associated resource to a third party and otherwise keeps the resource available for network service on a non-interruptible basis.

1691. NRECA, however, argues that contracts with LD provisions are typically considered firm products, so long as they cannot be curtailed for economic reasons alone. NRECA requests that the Commission confirm its understanding that the mere inclusion of an LD provision in a contract does not make the sale non-firm, provided that the sale cannot be curtailed only for economic reasons.

Commission Determination

1692. The Commission adopts the proposed definition of a Non-Firm Sale and incorporates that defined term in section 30.4 of the *pro forma* OATT. Network customers may use network resources for third party sales only if the sale is on a non-firm basis. This ensures that the network resource is available to serve the network load on an uninterruptible basis. We conclude that it would be inappropriate, as some commenters suggest, to relax the definition of a Non-Firm Sale to include any sale that is not otherwise firm enough to be designated as a network resource. We address the requirements for designation of network resources in section V.D.6, concluding that not all contracts with LD provisions are sufficiently firm to be eligible for designation. There we explain that only LD provisions that provide for ''make whole'' remedies are sufficiently firm to be designated as network resources. It does not follow, however, that all remaining contracts with LD provisions are non-firm. The very existence of an LD provision indicates that interruption of service will result in liability and, thus, such contracts cannot automatically be considered Non-Firm Sales for purposes of section 30.4. To allow otherwise would create conflicting incentives for the network customer.

d. Pre-Confirmed Application

NOPR Proposal

1693. Incident to the proposal to give priority to requests that are pre-confirmed, the NOPR proposed a new definition of Pre-Confirmed Application.

Comments

1694. No commenters oppose the Commission's proposed definition of a Pre-Confirmed Application.

Commission Determination

1695. The Commission adopts the proposed definition of Pre-Confirmed Application in order to implement the reforms adopted above regarding the priority of transmission service requests under the *pro forma* OATT.

e. NOPR Proposals Not Adopted

Economy Energy

1696. The Commission also proposed in the NOPR to adopt a definition of ''economy energy'' incident to its proposed changes to section 28.4 regarding the use of secondary network service. As discussed in section V.D.7, the Commission retains the existing requirement in section 28.4 that permits use of secondary network service ''to deliver energy to its Network Loads.'' The proposed definition of ''economy energy'' is therefore unnecessary.

f. Commenter Proposals

1697. Several commenters request that the Commission amend or add other definitions in the *pro forma* OATT.

(1) Network Transmission Service

Comments

1698. TDU Systems and Northwest Parties contend that, to help eliminate undue discrimination, the Commission should modify the definitions of ''network load'' and ''network operating committee'' in the *pro forma* OATT. Although the *pro forma* OATT already defines ''network load'' to include wholesale native load, TDU Systems contend that transmission providers frequently either give preference to their own retail native load or ignore wholesale customer native load in planning and expansion of the system and in ATC calculations for processing transmission service requests. TDU Systems argue that comparable treatment of wholesale native load and retail native load is required in all respects in light of the definition of ''network load.'' At the same time, TDU Systems argue that the definition of ''network load'' unreasonably restricts a transmission customer from serving a part of its load at a given delivery point with non-network resources since it provides that a customer ''may not designate only part of the load at a discrete Point of Delivery.''

1699. Northwest Parties also assert that the Commission should revise the definition of ''network load'' to permit point-to-point service and network service to the same network load if the point-to-point service is ignored in calculating load ratio share. Northwest Parties also argue that the Commission should allow point-to-point and network service to the same network load if the point-to-point service is purchased as non-firm.

1700. EEI replies in opposition to TDU Systems' proposal to eliminate the requirement that a network customer may designate only part of its load delivery as a network load. EEI argues that TDU Systems are incorrect in asserting that the definition of ''network load'' prohibits a network customer from serving part of its load with non-network resources and secondary network service to serve part, or even

all, of its network load. EEI contends that adoption of TDU Systems' proposal would eliminate one of the fundamental principles on which network service is founded: That the network customer must pay for network service based on its entire load, including load served by behind the meter generation, since the transmission provider must plan its transmission system to serve the customer's entire load.

1701. PNM–TNMP agree on reply that Commission should reject a change to the definition in the *pro forma* OATT regarding network load. PNM-TNMP state that the proposal presupposes that transmission providers discriminate against transmission customers and provides preferential treatment to their own retail native load in terms of planning and expansion of the system and in ATC calculations for processing transmission service requests. PNM–TNMP contend that they treat retail native load comparably with other network customers in all aspects and believe that any problems encountered by a transmission customer regarding undue discrimination should be addressed through the enforcement or complaint process, and that a change to the *pro forma* OATT is not warranted.

Commission Determination

1702. The Commission declines to modify the definitions of ''network load'' and ''network operating committee.'' The reforms related to ATC calculation and transmission planning adopted in this Final Rule adequately address the concerns regarding undue preference of native load in those areas. With regard to the request to allow network customers to serve part of their load with non-firm point-to-point service and part with network service, the Commission already determined in Order Nos. 888 and 888–A that a transmission customer is not allowed to take a combination of both network and point-to-point transmission service to serve the same discrete load.[963] We are not persuaded to modify that policy here.

(2) Firm and Non-Firm Transmission Service

Comments

1703. Powerex contends that ''firm transmission service'' is not adequately defined or sufficiently described in the *pro forma* OATT to ensure that a transmission customer is not being required to pay for firm service that is curtailed on a regular basis. For example, Powerex states the Commission could require that firm transmission service be available at least 95 percent of the time (excluding force majeure curtailments) in order for transmission to be defined as ''firm.''

1704. Powerex also contends that ''non-firm transmission service'' is interpreted differently in different regions. In the Pacific Northwest, Powerex asserts that non-firm service implies a lower curtailment priority but only as a result of actual transmission system constraints (*i.e.*, once the operating hour has begun, higher priority firm reservations cannot implement schedules over lower priority non-firm reservation). In contrast, Powerex argues that, for some transmission providers located in the Desert Southwest, transmission capacity associated with firm service reservations that have capacity schedules attached to them (*e.g.*, to deliver operating reserves) can also be sold as non-firm service that could be interrupted in the operating hour by the firm reservation. Powerex believes that these two types of service could be described as non-firm, non-interruptible (for the Pacific Northwest) and non-firm, interruptible (for the Desert Southwest).

Commission Determination

1705. The Commission finds that the clarifications proposed by Powerex are unnecessary to remedy undue discrimination in the provision of open access transmission service. In section V.D.8 of this Final Rule, the Commission requires transmission providers to post additional information regarding curtailments in order to provide transparency and allow customers to determine whether they have been treated in the same manner as other transmission system users. We conclude that existing compliance and enforcement procedures, coupled with these new posting requirements, are sufficient to address improper curtailments of service.

(3) System Impact Study

Comments

1706. Powerex urges the Commission to modify sections 1.47 and 17.5 of the *pro forma* OATT to clarify that transmission providers are not required to perform system impact studies for short-term service requests. Specifically, Powerex requests that the Commission amend the definition of a ''system impact study'' to refer only to requests for long-term firm point-to-point service or network service. Powerex argues that short-term firm point-to-point service requests do not require transmission providers to upgrade their systems and, as a result, requiring system impact studies for short-term requests often creates unnecessary burdens for transmission providers by mandating them to use limited resources to perform studies that do not offer significant benefits to customers. Powerex contends that the 60-day study period is particularly ill-suited for short-term transmission requests, most of which are for service that must commence within the study period.

Commission Determination

1707. The Commission declines to modify the definition of ''system impact study'' or otherwise modify section 17.5 to restrict system impact studies only to exclude reference to short-term point-to-point service. Regardless of the length of a service request, a transmission provider must assess whether a system impact study is required to evaluate the request for transmission service. Only upon the completion of such an assessment will the transmission provider be able to identify the impact a particular request will have on the grid. We conclude that eliminating or shortening the system impact study period could jeopardize system reliability and therefore reject the modifications proposed by Powerex.

(4) Definitions for RTOs, ISOs and ITCs

Comments

1708. Wisconsin Electric and International Transmission argue that the terms used in the *pro forma* OATT are inadequate when applied to RTO regions, especially in MISO. International Transmission and Wisconsin Electric assert that, in an RTO, the transmission provider and transmission owner are separate entities with separate functions, thus creating a need for separate definitions. They also contend that additional definitions may be needed when the transmission owner is an independent stand-alone transmission company operating within the RTO.

1709. Wisconsin Electric requests that the Commission define the term ''transmission owner'' in the *pro forma* OATT and specify which of its provisions are applicable to the transmission provider and which apply to the ''transmission owner.'' Additionally, Wisconsin Electric states that the *pro forma* OATT includes a definition for ''control area'' and the NOPR refers to the geographic area served by transmission providers as its control area, which in Wisconsin Electric's view is inaccurate in the case of MISO. Wisconsin Electric explains MISO has shifted to the use of the NERC

[963] *See* Order No. 888 at 31,736; Order No. 888–A at 30,259.

functional model and uses terms such as ''balancing authorities,'' ''generator operators,'' ''reliability authorities,'' and the like. Wisconsin Electric therefore requests that the Commission supplant the term ''control area'' in the *pro forma* OATT with a term that is predicated on the performance of a particular function, not the type of entity performing the function.

1710. International Transmission does not object to the Commission's proposal to largely retain the existing definitions set forth in the *pro forma* OATT, but asserts that the Commission should explicitly recognize in the Final Rule that such definitions may be inadequate when applied to RTOs. International Transmission also asks the Commission not to require RTOs with additional definitions in their tariffs to remove those definitions when complying with the Final Rule and, instead, expressly allow RTOs to propose additional definitions that may be necessary.

Commission Determination

1711. As explained in section IV.C, all transmission providers—including ISOs and RTOs—will have an opportunity to demonstrate that departures from the *pro forma* OATT, as modified by this Final Rule, are consistent with or superior to the terms and conditions of the *pro forma* OATT. Proposals to amend terms such as ''control area'' or ''transmission owner'' based on a particular set of facts are best left for case-by-case review.

(5) Other Definitions

Comments

1712. Ameren advocates the modification of a number of other *pro forma* OATT definitions. Ameren proposes definitions for ''source'' and ''sink,'' as well as additional provisions in section 22.2 governing source and sink of transmission. Ameren also requests clarification of the word ''use'' in section 30.8, arguing that some entities have assumed that ''use'' means scheduled amounts. Ameren argues for an improved definition of ''transmission peak'' because the data necessary no longer resides with the transmission owner in an RTO or ISO. Finally, Ameren suggests a revised definition of ''long-term firm,'' which would include only contracts that are longer than one year, not just one year or longer, arguing it would reduce the number of contracts that are only one-year in length that are used in the denominator for purposes of calculating the load ratio share and for ratemaking purposes. On this latter point, Ameren asserts that such contracts should be reflected as a revenue credit instead. In addition, Ameren believes that the current definition of long-term firm point-to-point service in section 1.18 of the *pro forma* OATT makes calculation of load ratio share very difficult in the modern RTO/Seams Elimination Cost Allocation (SECA) environment.

Commission Determination

1713. The Commission is not persuaded to adopt the revisions proposed by Ameren. We believe that what constitutes source and sink is sufficiently addressed in Order No. 888 and OASIS related proceedings and we will not expand the discussion here.[964] Order No. 888 also made clear that there are no ''load ratio'' limitations on the use of interfaces under section 30.8 of the *pro forma* OATT.[965] Otherwise, requests for interface capacity are subject to the *pro forma* OATT procedures. Moreover, Ameren has failed to justify revising the definition of ''transmission peak.'' While peak load data ultimately resides with the RTO or ISO, each transmission provider coordinates this type of data with RTO or ISO. Finally, we reaffirm that long-term firm service is service with a term of one year or more. Modifying the term of long-term service to reduce the number of contracts used in the denominator for purposes of calculating the load ratio share and for ratemaking purposes may affect how the transmission provider plans its system to service customers and has not been justified.

E. Enforcement

1714. The Commission attaches substantial importance to strengthening compliance with the OATT, on monitoring and auditing OATT compliance, including its staff's efforts to resolve disputes about compliance through the Enforcement Hotline and other dispute resolution mechanisms, and on investigating potential and alleged OATT violations. The expansion of the Commission's enforcement powers pursuant to EPAct 2005 directly augmented its ability to enforce the OATT by, among other things, providing authority to assess civil penalties of up to $1 million for each day that an OATT violation continues. The Commission intends to use its enforcement powers with respect to the OATT in a fair and even-handed manner, pursuant to the principles set forth in the Policy Statement on Enforcement.

1. General Policy

a. Compliance Review Regime

NOPR Proposal

1715. The Commission proposed to maintain a strong program to audit compliance with the new *pro forma* OATT. The audit program would include operational audits similar to past OATT compliance audits, during which staff may collect information on implementation of a transmission provider's OATT. The Commission stated that it would issue public reports of audit results and noted that contested audits would be subject to the Commission's Final Rule on contested operational audits.[966]

Comments

1716. Most initial commenters support a strong staff audit program.[967] Other commenters counter that staff audits will not be needed if the Commission issues a corrected *pro forma* OATT, especially with respect to RTOs and ISOs.[968] These commenters argue that formal complaints, Enforcement Hotline calls and random audits sufficiently inform staff of OATT compliance issues as to make additional staff audits unnecessary. Southern asserts that, under the separation of function policy, Commission audit staff should be separated from investigative and enforcement staff. Particular commenters contend that the Commission should focus compliance efforts on specific OATT provisions, such as those concerning network service (Arkansas Cities), or on structural issues such as independent planning and operation of transmission facilities (Reliant). Nevada Companies suggests that the Commission set up regional audit teams to foster strong working relationships with transmission providers. EPSA asks the Commission to adopt stronger measures than a staff audit program to monitor compliance. EPSA's proposed measures include requiring transmission providers to: designate compliance officers to report OATT violations to company boards; undergo compliance audits by an

[964] Redirect-related issues are addressed in section V.D.4.

[965] *See* Order No. 888 at 31,753–54; Order No. 888–A at 30,304–5; *see also Sierra Pacific Power Co.*, 81 FERC ¶ 61,136 at 61,139–40 (1997); *New England Power Pool*, 83 FERC ¶ 61,045 at 61,248 (1998).

[966] *See Procedures for Disposition of Contested Audit Matters*, Order No. 675, 71 FR 9698 (Feb. 27, 2006), FERC Stats. & Regs. ¶ 31,209 (2006) (Contested Audit Matters), *order on rehearing and clarification*, Order No. 675–A, 71 FR 29779 (May 24, 2006), FERC Stats. & Regs. ¶ 31,217 (2006).

[967] *E.g.*, APPA, AWEA, EEI, Morgan Stanley, NRG, Southern, TAPS, and Williams.

[968] *E.g.*, Ameren, PNM–TNMP, and South Carolina E&G. In reply comments, TDU Systems urge the Commission to reject this contention.

independent auditor in response to material violations; and hire an independent administrator to oversee OATT compliance and regional planning efforts if a transmission provider has not complied with its new OATT within a specified period of time. In reply comments, MISO opposes EPSA's proposal for a third-party compliance administrator for RTOs and ISOs if they do not timely comply with new OATT provisions, arguing that these entities already are independent administrators of transmission grids and planning processes. MISO asserts that inserting an ''independent'' authority over OATT compliance by RTOs and ISO would create a superfluous bureaucratic layer. NRECA opposes EPSA's proposal because a third-party compliance administrator or auditor would be too expensive and the Commission cannot delegate its compliance authority.

1717. Noting that the Commission required RTOs to undertake extensive market monitoring in Order No. 2000, PJM states that the Commission should require in the *pro forma* OATT a similar degree of market monitoring in non-RTO areas to make available to Commission staff information needed to ascertain market abuses in these areas. PJM asserts that any such market monitoring should be performed by entities independent of the non-RTO utilities, with Commission oversight. Indicated Parties reply that RTOs' market monitors should examine market power in transmission planning because RTOs delegate transmission operations and planning duties to constituent transmission owners that retain incentives to benefit affiliates or vertically-integrated divisions.

Commission Determination

1718. The Commission adopts the NOPR proposal to emphasize a strong staff audit program for compliance with OATT requirements, including operational audits. Staff audits of OATT compliance may be random or targeted with respect to the entities being audited or particular provisions of the OATT that are scrutinized. Because its responsibility is to assess and ensure compliance with the OATT, staff will maintain discretion as to the entities it audits and the subject matter of these audits. The Commission encourages transmission providers to designate employees as compliance officers for the OATT or to conduct third-party audits relating to OATT compliance when appropriate. However, we do not believe that staff should forego an audit of an entity's OATT compliance solely because a transmission provider has designated an OATT compliance officer, engaged a third-party auditor, or transferred transmission functions to an independent transmission coordinator. We decline EPSA's proposal to require such actions, except on a case-by-case basis when warranted.

1719. We disagree with PJM's request that the Commission require third-party market monitoring to ascertain market abuses occurring with respect to transmission providers outside RTOs and ISOs, subject to Commission oversight. In a number of instances since 2000, the Commission has established third-party monitoring of a transmission provider located outside an RTO or ISO.[969] These monitors were established on a case-specific basis to address concerns related to the transmission provider at issue. We have no evidence to support requiring monitors for every transmission provider in the Nation. Further, the Commission has access to substantial information on OATT compliance by transmission providers that are not RTOs or ISOs through their postings on OASIS, informal and formal complaints by customers, and reports by market monitors for such transmission providers. Indeed, the revised *pro forma* OATT will greatly enhance our oversight and enforcement capabilities by increasing the transparency of many critical functions under the *pro forma* OATT, such as ATC calculation and transmission planning. PJM has not provided any evidence that the enhanced transparency under the OATT, coupled with the Commission's own monitoring and audits of OATT compliance and its enhanced enforcement authority, will be insufficient to ascertain and deter OATT violations. We do not object to the suggestion of Indicated Parties that RTO and ISO market monitors examine market power in transmission planning, so long as the market monitors' activities in this respect are consistent with these roles as set forth in the applicable RTO and ISO tariffs.

1720. We do not agree with Southern's assertion that the Commission's audit staff should be separated from its investigative and enforcement staff. The Commission's separation of functions regulation[970] generally permits Commission auditors, investigators and enforcement staff to speak freely to persons inside the Commission as to the subject matter of their inquiries.[971] Southern has not cited any justification for restricting communications among these staff members or from them to the Commission. To the contrary, a free flow of communications among auditors and investigators, consistent with the Commission's rule on staff separation of functions, should increase the efficiency of the Commission staff's compliance program and enforcement efforts.[972]

b. Use of Independent Third Party Audits

NOPR Proposal

1721. The Commission proposed not to mandate the use of third party auditors and, instead, proposed that Commission staff conduct audits of compliance with the *pro forma* OATT. The Commission stated that it may require third party compliance audits as part of a compliance plan following a Commission staff audit report. In response to situations such as systematic OATT violations, a pattern of repeated violations, or violations that require ongoing monitoring, the Commission could require an audited party to hire a third party to continue compliance audits.

Comments

1722. Most initial commenters agree with the Commission's proposal to require third-party audits only as part of an individual post-audit compliance plan.[973] EEI and Southwestern Coop submit that selection of third-party auditors should be subject to Commission review and approval, while South Carolina E&G cautions that the Commission should carefully weigh the costs and benefits of independent auditors before requiring their use. Southern suggests that third-party audits be required only for systematic, egregious OATT violations. Entegra doubts that third-party auditors can remedy patterns of discrimination by transmission providers against independent merchant generators.

[969] *See, e.g., Duke Power,* 113 FERC ¶ 61,288 (2005); *MidAmerican Energy Holdings Co.,* 113 FERC ¶ 61,298 (2005).

[970] 18 CFR 385.2202.

[971] *Statement of Administrative Policy on Separation of Functions,* 101 FERC ¶ 61,340 at P 24–26 (2002).

[972] *See also* Order No. 675–A at P 25–29 (the Commission's regulation and policy statement on separation of functions remain applicable following EPAct 2005, and efficiency and sound administrative practice continue to favor the sharing of information between the Commission's audit staff and investigative staff).

[973] *E.g.,* Alberta Intervenors, Arkansas Commission, Constellation, EEI, EPSA, MISO/PJM States, Nevada Companies, PNM–TNMP, South Carolina E&G, Southwestern Coop, and Suez Energy NA.

Commission Determination

1723. The Commission adopts the NOPR proposal not to require generally the use of third party auditors to assess compliance with the OATT. We believe that a requirement for the use of third-party audits in compliance plans should depend on particular facts, including the egregiousness and extent of violations found during a staff audit or investigation and the appropriate scope or cost of a third-party audit. As stated above, we encourage transmission providers to use third-party compliance audits when appropriate to supplement our staff's audit efforts.

2. Civil Penalties

1724. In the NOI, the Commission asked for comment as to whether it should address imposing remedies or penalties against transmission providers as part of OATT reform. After the NOI, the Commission issued its Policy Statement on Enforcement and, in response to specific authority granted it in EPAct 2005, issued Order No. 670, the Anti-manipulation Rule. [974]

a. Whether Civil Penalties Should Be Specified in the OATT

NOPR Proposal

1725. Aside from operational penalties proposed in the NOPR, [975] the Commission proposed not to establish a schedule of enforcement remedies and sanctions in the *pro forma* OATT. Rather, the Commission stated that it would address OATT violations and appropriate responses on a case-by-case basis, consistent with the Policy Statement on Enforcement. The Commission explained that it may impose civil penalties when warranted, after consideration of applicable factors listed in the Policy Statement on Enforcement; OATT violators also will be expected to disgorge unjust profits when they can be determined or reasonably estimated.

Comments

1726. The majority of parties filing comments on this issue agree that the Commission should assess civil penalties on a case-by-case basis under the guidance of the Policy Statement on Enforcement. [976] Other commenters instead support incorporation in the *pro forma* OATT of a schedule of significant remedies and sanctions for specific violations to assure transparency and certainty as to situations in which penalties would be assessed and to deter anticompetitive behavior. [977] EPSA advises that the Commission refrain from setting pre-determined limits on penalty amounts because each violation of a specific *pro forma* OATT provision may present different facts that may warrant different outcomes. Nevada Companies suggest that the Commission provide incentives to construct new transmission infrastructure rather than implement an overbearing penalty regime because additional transmission capacity itself will resolve many complaints.

1727. Wisconsin Electric concludes that OATT violations by non-profit RTOs and ISOs should not be subject to civil penalties because they would be passed through to customers and not act as an effective deterrent. [978] Rather than assess a penalty in response to an RTO's or ISO's OATT violation, Wisconsin Electric suggests that the Commission could intensify oversight of an RTO's or ISO's OATT compliance. NorthWestern comments, in contrast, that RTOs and ISOs should not be exempted from civil penalty assessments for their OATT violations, because these violations could have as much or more adverse effects on transmission access or system reliability as would OATT violations by other transmission providers.

1728. Several commenters support the Commission's proposal to consider mitigating factors listed in the Policy Statement on Enforcement in assessing civil penalties for OATT violations. [979] In this regard, EEI states that the Commission should clarify that when a party engages in self-reporting, compliance programs or cooperation with Commission staff, the Commission will recognize the party's attorney-client privilege. [980]

1729. EEI suggests that the Commission establish ''safe harbors'' against civil penalties for OATT violations involving reasonable interpretations of tariff provisions or for actions taken for reliability purposes that are consistent with good utility practice. PNM–TNMP and Southern ask the Commission to clarify that LSEs will not be penalized for OATT violations for taking actions necessary to meet their native load obligations since, pursuant to new FPA section 217, [981] LSEs should not be considered to have engaged in ''undue discrimination or preference'' for certain actions required to serve native load customers. TDU Systems argue in reply comments that a ''safe harbor'' approach could permit unduly discriminatory or preferential behavior that would be penalized under a case-by-case approach. Entegra replies that safe harbors for ''reasonable'' tariff interpretations would give vertically-integrated utilities license to discriminate against competitors, and suggests that the Commission ensure that the OATT operates as a sword for attacking undue discrimination, not as a shield for defending it. Occidental replies that transmission providers with a Commission-approved independent transmission coordinator should not be insulated from tariff-based civil penalties and other sanctions.

Commission Determination

1730. Following enactment in EPAct 2005 of enhanced authority for the Commission to assess civil penalties for violations of statutes it administers and of regulations and orders under these statutes, the Commission issued the Policy Statement on Enforcement to set forth how it intends to use this authority consistent with the statute. [982] Underlying this policy is the recognition that the appropriate basis for assessment of a civil penalty for a violation is an examination of the facts and circumstances relating to that violation, and the use of discretion and flexibility to address it on its merits. This examination includes a review of all applicable mitigating factors set forth in the Policy Statement on Enforcement. While we understand that establishing a schedule of civil penalties for violations of particular provisions of the *pro forma* OATT would establish greater specificity with respect to civil penalties, the Commission already concluded in the Policy Statement on Enforcement that it would ''not prescribe specific penalties or develop formulas for different violations.'' [983] We see no justification to depart from

[974] *Prohibition of Energy Market Manipulation,* III FERC Stats. & Regs. ¶ 31,202 (2006), *order denying rehearing,* 114 FERC ¶ 61,300 (2006).

[975] NOPR at P 384.

[976] *E.g.,* APPA, EEI, EPSA, Nevada Companies, PNM–TNMP, Southern, and Southwestern Coop. Southwestern Coop also urges speedy review of violations and swift assessment of penalties. In reply comments, Sacramento adds that the Commission may assess civil penalties against a transmission provider that engages in unduly discriminatory behavior in its transmission planning process.

[977] *E.g.,* Arkansas Commission and ELCON.

[978] Wisconsin Electric asserts that the Commission has recognized this principle in other contexts, *citing Financial Reporting and Cost Accounting, Oversight and Recovery Practices for Regional Transmission Organizations and Independent System Operators,* FERC Stats. & Regs. ¶ 35,546 at P 9 (2004).

[979] *E.g.,* Nevada Companies and PNM–TNMP.

[980] EEI observes that the Commission held in its final rule on contested audit procedures that ''an audited person who appropriately interposes the attorney-client privilege will not be considered non-cooperative.'' Contested Audit Matters at P 35.

[981] 16 U.S.C. 824q(k).

[982] Policy Statement on Enforcement at P 1.

[983] *Id.* at P 13.

that decision with respect to violations of OATT provisions.

1731. Several commenters ask that we establish specific ''safe harbors'' or exemptions from assessment of civil penalties for OATT violations in specific circumstances or with respect to specific types of entities that may engage in OATT violations. We decline to create automatic safe harbors for specific circumstances or specific types of OATT violations. The creation of such exemptions would require us to forego the examination of the specific circumstances of particular violations that we described in the Policy Statement on Enforcement as the touchstone of our policy in assessing civil penalties. Instead, we will decide requests for leniency in particular cases by using the principles set forth in the Policy Statement on Enforcement and considering all applicable mitigating factors listed therein.[984]

1732. Likewise, we will not establish an automatic exemption from civil penalty assessments for OATT violations committed by particular types of entities such as non-profit RTOs and ISOs. The Commission decided last year that it would not automatically exempt RTOs and ISOs from penalties assessed by the Electric Reliability Organization or Regional Entities for reliability violations pursuant to new FPA section 215. In Order No. 672, the Commission stated, ''[w]hile we recognize that RTOs and ISOs have some unique characteristics, we do not believe that a generic exemption from any type of penalty is appropriate for any entity, including an RTO or ISO.'' [985] We believe the same principle applies to civil penalties for OATT violations. However, in assessing civil penalties for OATT violations, we will consider all applicable facts relating to the violator, including the effect of potential penalties on the financial viability of the violator.[986]

1733. We agree with commenters who state that the Commission and its staff should recognize the valid assertion of the attorney-client privilege in the context of investigations, audits and other fact-finding activities. As EEI points out, we recently stated with respect to audits that we would not consider an entity to be uncooperative with audit staff if the entity appropriately asserts that a communication or document is covered by that privilege.[987] We take the same position with respect to investigations or other fact-finding undertakings with respect to possible OATT violations.

1734. In the Policy Statement on Enforcement, however, the Commission drew a distinction between cooperation, which we expect from entities subject to the Commission's jurisdiction given their statutory obligation to provide information to us, and ''exemplary'' cooperation, which ''quickly ends wrongful conduct, determines the facts, and corrects a problem.'' [988] The Commission explained that we will give some consideration to exemplary cooperation and indicated that one example of such cooperation is a situation in which an entity being investigated provides to staff internal investigations or audit reports relating to misconduct. These investigations and reports may include information that an entity could properly shield from disclosure pursuant to the attorney-client privilege. We observe that an entity that is in a position to assert this privilege validly also has the option to waive it. If a waiver of attorney-client privilege, whether related to an internal investigation or audit or not, assists staff in ascertaining the facts relating to alleged or apparent misconduct, ends misconduct quickly or otherwise substantially advances an investigation or inquiry, that waiver may be an element in finding ''exemplary cooperation'' as described in the Policy Statement on Enforcement.[989]

b. Whether Transmission Providers Should Be Subject to Revocation of Market-Based Rates for OATT Violations

NOPR Proposal

1735. The Commission observed in the NOPR that some OATT violations, after applying the factors in the Policy Statement on Enforcement to all facts and circumstances, may merit revocation of market-based rate authority. Before considering revoking an entity's market-based rate authority for an OATT violation, the Commission proposed that it must find a nexus between the specific facts relating to the OATT violation and the entity's market-based rate authority. The Commission also proposed that if it determines, as a result of a significant OATT violation, to revoke the market-based rate authority of a transmission provider within a particular market, each affiliate of the transmission provider that possesses market-based rate authority would have that authority revoked in that market, effective on the date of revocation of the transmission provider's market-based rate authority.

Comments

1736. Most parties that submitted initial comments on this issue support the Commission's conclusion that, in certain circumstances, it may be appropriate to revoke the market-based rate authority of an entity that engages in an OATT violation.[990] The majority of these commenters support the Commission's proposal to do so only if it finds a nexus between the OATT violation and the entity's market-based rate authority.[991]

1737. Some commenters oppose the requirement for a nexus between the OATT violation and the entity's market-based rate authority because the Commission has not stated what facts would be sufficient to show such a nexus.[992] EPSA and NRECA (in reply comments) contend that if the Commission does not remove the ''nexus'' condition, it should clarify what constitutes a ''nexus'' between an OATT violation and an entity's market-based rate authority. Similarly, PNM–TNMP argues that such a nexus must be clear and fact-specific, consistent with the Policy Statement on Enforcement. TDU Systems contend in reply

[984] We have also provided clarification on the procedures that would apply to the assessment in formal proceedings of civil penalties relating to OATT violations in our recent *Statement of Administrative Policy Regarding the Process for Assessing Civil Penalties,* 117 FERC ¶ 61,317 (2006).

[985] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards,* Order No. 672, 71 FR 8662 (Feb. 17, 2006), FERC Stats. & Regs. ¶ 31,204 at P 634 (2006), *order on reh'g,* Order No. 672–A, FERC Stats. & Regs. ¶ 31,212 (2006).

[986] Policy Statement on Enforcement at P 20. *Cf.* Order No. 672–A at P 56–57 (holding that for determining a penalty pursuant to the FPA section 215 reliability program, circumstances such as organization structure or non-for-profit status will be considered, but that there should not be an automatic exemption from monetary penalties for RTOs and ISOs).

[987] *Citing* Contested Audit Matters at P 35.

[988] Policy Statement on Enforcement at P 26.

[989] *See In re PacifiCorp,* 118 FERC ¶ 61,026 at P 3, 8 and attached stipulation and consent agreement at P 24 (2007) (referring to transmission provider's waivers of attorney-client privilege as an element in making finding of exemplary cooperation with investigation when approving settlement assessing civil penalty that resolved a transmission provider's violations of its OATT, among other matters); *In re Entergy Services, Inc.,* 118 FERC ¶ 61,027 at P 15, 18 (2007) (same).

[990] *E.g.*, EEI, ELCON, Morgan Stanley, Nevada Companies, Northwest IOUs, Progress Energy, PNM–TNMP, Sempra Global, Southern, and TDU Systems.

[991] *E.g.*, EEI, Nevada Companies, Northwest IOUs, Progress Energy, PNM–TNMP, Sempra Global, and Southern.

[992] *E.g.*, APPA.

comments that, at a minimum, a transmission provider or its affiliate that has market-based rate authority must overcome a rebuttable presumption that its OATT violation has the requisite ''nexus'' to support revocation of such authority.

1738. Other commenters argue that a serious OATT violation removes the mitigation of transmission market power provided by adherence to an OATT, thereby eviscerating one of the essential requirements for market-based rate authority.[993] EEI and PNM–TNMP reply that not every OATT violation diminishes the availability of transmission service so as to establish vertical market power.

1739. APPA and TDU Systems suggest in reply comments that the proposed nexus condition would unduly limit any sanctions, because the shareholders of the violator could still reap the benefits of such a violation if an affiliate that did not have any knowledge of the OATT violation could continue to engage in transactions under market-based rate authority. According to APPA, this possibility could lessen the incentive for senior management over a transmission provider and affiliates to make OATT compliance a high priority. As such, APPA and TAPS suggest that the Commission consider revoking a transmission provider's market-based rate authority for a ''material'' OATT violation that effectively denies, delays, or diminishes a customer's access to transmission service essential to mitigating transmission market power.

1740. TDU Systems caution that revocation of market-based rate authority may not be sufficient to deter OATT violations if reversion to cost-based rates may provide a transmission provider with the ability to recover all costs and receive higher revenues than competitive markets might otherwise produce. Therefore, TDU Systems ask that the Commission consider assessment of civil penalties in addition to revocation of market-based rate authority.

1741. The majority of commenters disagree, however, with the Commission's proposal to revoke the market-based rate authority of all affiliates of a transmission provider to the same extent that we revoke that transmission provider's market-based rate authority.[994] These commenters assert that affiliates that have no knowledge of, or involvement in, their affiliated transmission provider's unlawful activities should not lose their market-based rate authority as a result of the transmission provider's OATT violation. NRECA replies that market-based rate authority is a privilege, not a right, and asserts that the Commission should revoke market-based rate authority in response to an OATT violation that indicates that a public utility possesses market power.

1742. APPA also suggests that, short of revocation of a transmission provider's market-based rate authority in response to an OATT violation, the Commission could condition that authority, or the market-based rate authority of the transmission provider's affiliates. APPA provides the following examples of such conditions: A requirement to participate in joint planning of transmission facilities with the transmission provider's network customers and offer these customers appropriate credits under OATT section 30.9; an offer of joint transmission ownership opportunities to LSEs for new transmission facilities on reasonable terms and conditions; and an offer to network service customers to participate in the ownership of the transmission provider's existing transmission system on a load ratio share basis.

Commission Determination

1743. We adopt the NOPR proposal to revoke an entity's market-based rate authority in response to an OATT violation only upon a finding of a specific factual nexus between the violation and the entity's market-based rate authority. We believe that the ''nexus condition'' is required in order to ensure that our actions are not arbitrary or capricious or based on an inadequate factual record. We note that in this context the Commission has the burden to show a factual nexus. We do not assign a burden on the violator to show the lack of this nexus.

1744. Determining what would be a sufficient factual nexus between an OATT violation and revocation of the violator's market-based rate authority is best left to a case-by-case consideration. The wide range of positions among commenters on how to define a sufficient factual nexus itself suggests that this finding is best made after review of a specific factual situation. Some commenters assert that a finding of a ''serious'' or ''material'' violation of the OATT would be sufficient. We disagree. While an entity's inconsequential OATT violation would not serve as a basis for revoking that entity's market-based rate authority, our view is that the nexus condition requires us to find both that a substantial OATT violation has occurred and that the violation either related to the exercise of the violator's market-based rate authority or violated a specific condition of that authority.

1745. The Commission emphasizes that we have discretion to fashion remedies for OATT violations that relate to the violator's market-based rate authority in instances in which we do not find a factual nexus justifying revocation of that authority. For example, in appropriate circumstances, we may modify or add additional conditions to the violator's market-based rate authority or impose other requirements to help ensure that the violator does not commit future, similar misconduct. Nor is revocation of market-based rate authority the only action we may take to respond to an OATT violation that meets the nexus condition. We will consider whether to impose sanctions such as assessment of civil penalties for particularly serious OATT violations in addition to revocation of the violator's market-based rate authority.

1746. We do not adopt our proposal from the NOPR to revoke the market-based rate authority of each affiliate of a transmission provider that loses its market-based rate authority within a particular market as a result of an OATT violation. Rather, we will create a rebuttable presumption that all affiliates of a transmission provider should lose their market-based rate authority in each market in which their affiliated transmission provider loses its market-based rate authority as a result of an OATT violation. We will allow an affiliate of a transmission provider to retain its market-based rate authority in a market area if the affiliate overcomes the rebuttable presumption with respect to that market area.

1747. We expect that the issue of potential revocation of market-based rate authority will arise as a result of an OATT violation in a market in which the transmission provider possesses transmission market power through the ownership of transmission facilities in that market. For these markets, we have evaluated whether a transmission provider should receive authority to make sales of electric power for resale at market-based rates using a four-prong analysis. In this analysis we consider whether the transmission provider and its affiliates have adequately mitigated market power in generation and transmission, whether the transmission provider or its affiliates can erect other barriers to entry, and whether there is evidence that the transmission provider and its affiliates have engaged in

[993] *E.g.*, APPA, EPSA, and TAPS.

[994] *E.g.*, EEI, Nevada Companies, Northwest IOUs, Progress Energy, PNM–TNMP, Sempra Global, and Southern.

affiliate abuse or reciprocal dealing.[995] In particular, we have long held that the existence of an OATT is deemed to mitigate vertical market power and transmission market power held by a transmission provider and its affiliates in a particular market. An OATT violation by a transmission provider in a market in which it possesses transmission market power that merits revocation of the transmission provider's market-based rate authority may call into question whether the transmission provider's affiliates continue to qualify for market-based rates in that market under the standards that we have established.[996] As a result, we believe that it is appropriate to establish a presumption in this circumstance that if we find that a transmission provider should lose its market-based rate authority in a market in which it possesses transmission market power, we will revoke the market-based rate authority in that market of all affiliates of the transmission provider.

1748. We are mindful, however, that the circumstances of a particular affiliate may not always justify the imposition of a remedy so severe as revocation of market-based rate authority in a particular market when its affiliated transmission provider loses its market-based rate authority in that market as a result of an OATT violation. To afford due process to a transmission provider's affiliates in that situation, and to ensure that a determination to revoke market-based rate authority in a particular market for a transmission provider and all of its affiliates that possess such authority is adequately based upon record evidence and not arbitrary or capricious, we will allow an opportunity for each such affiliate to make a showing that it should retain its market-based rate authority or that enforcement action against it should be less severe than revocation. The determination whether an affiliate has overcome the rebuttable presumption depends on an analysis of specific facts in the record. Relevant facts would include, but are not limited to, whether: (1) The transmission provider and the affiliate were under the same control; (2) the affiliate knew of, participated in or was an accomplice to the OATT violation; (3) the affiliate assisted the transmission provider in exercising market power; or (4) the affiliate benefited from the violation.

c. Whether Certain OATT Violations Should Be Considered Market Manipulation Under Section 222 of the FPA

NOPR Proposal

1749. The Commission proposed in the NOPR to decline to identify in the *pro forma* OATT specific conduct that constitutes *per se* market manipulation. The Commission proposed to consider on a case-by-case basis, if and when they arise, whether specific circumstances relating to OATT violations constitute market manipulation under the standards set forth in Order No. 670.

Comments

1750. All commenters on this issue concur with a case-by-case approach to it.[997] Southwestern Coop suggests that, as the Commission gains sufficient experience to describe particular misconduct as market manipulation *per se,* it should identify such misconduct in the OATT. While contending that the Commission should act with caution in listing behaviors that constitute *per se* market manipulation in view of the dynamic nature of markets, TDU Systems urge the Commission to specify in the OATT that transmission planning misconduct could constitute a form of market manipulation or abuse.

Commission Determination

1751. We adopt the NOPR proposal for a case-by case approach to considering whether OATT violations may constitute market manipulation. Without reference to a specific factual pattern developed in an investigation or on-the-record proceeding, the Commission is not in a position to identify market manipulation relating to OATT violations.[998]

VI. Information Collection Statement

1752. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting, record keeping, and public disclosure (collections of information) imposed by an agency.[999] Pursuant to OMB regulations, the Commission is providing notice of its proposed information collections to OMB for review under section 3507(d) of the Paperwork Reduction Act of 1995.[1000]

1753. The Commission identifies the information provided under Part 35 subpart C as contained in FERC–516 and Part 37 as contained in FERC–717. The Commission solicited comments on the need for this information, whether the information will have practical utility, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing respondents' burden, including the use of automated information exchanges. The Commission did not receive any specific comments regarding its burden estimates. Where commenters raised concerns that specific information collection requirements would be burdensome to implement, the

[995] In our recent NOPR on market-based rates for wholesale sales of electricity, the Commission proposed to discontinue referring to affiliate abuse among a transmission provider and its affiliates as a separate ''prong'' of our analysis of whether to grant market-base rate authority. The Commission instead proposed to address affiliate abuse by requiring that transmission providers and their affiliates comply with restrictions and conditions set forth in the regulations we propose in that proceeding. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities,* 71 FR 33102 (Jun. 7, 2006), FERC Stats. & Regs. ¶ 32,602 at P 13 (2006).

[996] We observe that specific situations in which transmission providers have agreed to resolve staff allegations that they engaged in OATT violations have involved transactions with affiliates. *See Idaho Power* (settlement of, among other issues, an Enforcement staff allegation that a transmission provider permitted its merchant function to request non-firm transmission to enable the merchant function to make off-system sales that by definition were not used to serve native load, so that the transmission did not qualify for the ''native load'' priority specified in section 28.4 of the transmission provider's OATT); *Cleco Corp.*, 104 FERC ¶ 61,125 (2003) (settlement between Enforcement staff and a utility holding company and its subsidiaries relating, in part, to the provision by a transmission provider of a unique type of transmission service that was neither made available to non-affiliates nor included in its FERC tariff); *Tucson Electric Power Co.*, 109 FERC ¶ 61,272 (2004) (operational audit in which staff found that, among other matters, a transmission provider permitted its wholesale merchant function to purchase hourly non-firm and monthly firm point-to-point transmission service using an off-OASIS scheduling procedure while the transmission provider did not post on its OASIS the availability of capacity on these paths); *South Carolina Electric & Gas Co.*, 111 FERC ¶ 61,217 (2005) (settlement of Enforcement staff allegation that a transmission provider made available firm point-to-point transmission service to its affiliated merchant function that did not submit transmission schedules with specific receipt points for the service as required by section 13.8 of the transmission provider's OATT); and *MidAmerican Energy Co.*, 112 FERC ¶ 61,346 (2005) (operational audit in which staff found, among other things, that a transmission provider permitted its wholesale merchant function to (a) use network transmission service to bring short-term energy purchases onto its system while it simultaneously made off-system sales, inconsistently with the preamble to Part III of the transmission provider's OATT and section 28.6 of its OATT; and (b) confirm firm network transmission service requests without identifying a designated network resource or acquiring an associated network resource, in some instances using this service to deliver short-term energy purchases used to facilitate off-system sales, inconsistent with section 29.2 or section 30.6 of the transmission provider's OATT). *See also* Commission orders cited in note 989 *supra*.

[997] APPA, Nevada Companies, PNM–TNMP, Southwestern Coop, and TDU Systems.

[998] Similarly, in issuing the *Anti-manipulation Rule*, we declined to provide specific examples of what would constitute market manipulation. Order No. 670 at P 64–67.

[999] 5 CFR 1320.11.

[1000] 44 U.S.C. 3507(d).

Commission has address those concerns elsewhere in the rule.

1754. The Commission estimates the burden for complying with the Final Rule is as follows: [1001]

Data collection	Number of respondents	Number of responses	Hours per response	Total annual hours
Part 35 (FERC–516)				
Conforming tariff changes	116	1	25	2,900
Revision of Imbalance Charges	116	1	5	580
ATC revisions	116	1	40	4,640
Planning (Attachment K)	116	1	200	23,200
Congestion studies	116	1	300	34,800
Attestation of network resource commitment	116	1	1	116
Capacity reassignment	116	1	100	11,600
Operational Penalty annual filing	116	1	10	1,160
Creditworthiness—include criteria in the tariff	116	1	40	4,640
Sub Total Part 35				83,636
Part 37 (FERC–717)				
ATC-related standards:				
NERC/NAESB Team to develop	1	1	1,920	1,920
Review and comment by utility	116	1	20	2,320
Implementation by each utility	116	1	40	4,640
Mandatory data exchanges	116	1	80	9,280
Explanation of change of ATC values	116	1	100	11,600
Reevaluate CBM and post quarterly	116	1	20	2,320
Post OASIS metrics; requests accepted/denied	116	1	90	10,440
Post planning redispatch offers and reliability redispatch data	116	1	20	2,320
Post curtailment data	116	1	10	11,160
Post Planning and System Impact Studies	116	1	5	580
Posting of metrics for System Impact Studies	116	1	100	11,600
Post all rules to OASIS	116	1	5	580
Sub Total (Part 37)				68,760
Total (Part 35 + Part 37)				140,476
Recordkeeping	116	1	40	4,640

1755. *Information Collection Costs:* No comments were received regarding the Commission's estimate of costs to comply with these requirements. The Commission has projected costs of compliance as follows:

Total Annual Hours for Collection:

Reporting + recordkeeping hours = 152,396 + 4,640 = 157,036 hours.

Cost to Comply:

Reporting = $17,373,144

152,396 hours @ $114 an hour (average cost of attorney ($200 per hour), consultant ($150), technical ($80), and administrative support ($25))

Recordkeeping = $7,478,888

Labor (file/record clerk @ $17 an hour) 4,640 hours @ $17/hour = $78,880

Storage 8,000 sq. ft. × $925 (off site storage) = $7,400,000

Total costs = $24,852,024

Labor $ ($17,373,144 + $78,880) + Recordkeeping Storage Costs ($7,400,000)

Title: FERC–516, Electric Rate Schedules and Tariff Filings; FERC–717 Standards for Business Practices and Communication Protocols for Public Utilities.

Action: Proposed Collections.

OMB Control Nos. 1902–0096 and 1902–0173.

Respondents: Business or other for profit.

Frequency of responses: On occasion.

Necessity of the Information: The Federal Energy Regulatory Commission adopts these amendments to its regulations adopted in Order Nos. 888 and 889, and to the *pro forma* open access transmission tariff, to ensure that transmission services are provided on a basis that is just, reasonable and not unduly discriminatory or preferential. The purpose of this rulemaking is to strengthen the *pro forma* OATT to ensure that it achieves its original purpose—remedying undue discrimination—not to create new market structures. We propose to achieve this goal by increasing the clarity and transparency of the rules applicable to the planning and use of the transmission system and by addressing ambiguities and the lack of sufficient detail in several important areas of the *pro forma* OATT. The lack of specificity in the *pro forma* OATT creates opportunities for undue discrimination as well as making the undue discrimination that does occur more difficult to detect. To accomplish this we are proposing five objectives: (1) To improve transparency and consistency in several critical areas, by providing for greater consistency in the calculation of ATC, (2) to reform the transmission planning requirements of the *pro forma* OATT to eliminate potential undue discrimination and support the construction of adequate transmission facilities to meet the needs of all LSEs, (3) to remedy certain portions of the *pro forma* OATT that may have permitted utilities to

[1001] These burden estimates applied only to the Final Rule and do not reflect upon all of FERC–516 or FERC–717.

discriminate against new merchant generation, including intermittent generation, (4) to provide for greater transparency in the provision of transmission service to allow transmission customers better access to information to make their resource procurement and investment decisions, as well as to increase the Commission's ability to detect any remaining incidents of undue discrimination; and (5) to reform and provide greater clarity in areas that have generated recurring disputes over the past 10 years, such as rollover rights, ''redirects,'' and generation redispatch. The reforms proposed in this Final Rule are intended to address deficiencies in the *pro forma* OATT that have become apparent since the implementation of Order No. 888 in 1996 and to facilitate improved planning and operation of transmission facilities.

1756. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, Attention: Michael Miller, Office of the Executive Director, Phone: (202) 502–8415, fax: (202) 273–0873, e-mail: *michael.miller@ferc.gov*.

1757. For submitting comments concerning the collections of information and the associated burden estimate(s), please send your comments to the contact listed above and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503 Attention: Desk Officer for the Federal Energy Regulatory Commission, phone (202) 395–3122, fax: (202) 395–7285. Due to security concerns, comments should be sent electronically to the following e-mail address: *oira_submission@omb.eop.gov*. Please reference the docket number of this rulemaking in your submission.

VII. Environmental Analysis

1758. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[1002] The Commission concludes that neither an Environmental Assessment nor an Environmental Impact Statement is required for this Final Rule under section 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale subject to the Commission's jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classifications and services.[1003]

VIII. Regulatory Flexibility Act Analysis

1759. The Regulatory Flexibility Act of 1980 (RFA) [1004] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. This rule applies to public utilities that own, control or operate interstate transmission facilities other than those that have received waiver of the obligation to comply with Order Nos. 888 and 889. The total number of public utilities that, absent waiver, would have to modify their current OATTs by filing the revised pro forma OATT is 116.[1005] Of these only six public utilities, or less than two percent, have output of four million MWh or less per year.[1006] The Commission does not consider this a substantial number and, in any event, each of these entities retains its rights to waiver of these requirements.[1007] The criteria for waiver that would be applied under this rulemaking for small entities is unchanged from that used to evaluate requests for waiver under Order Nos. 888 and 889. Accordingly, the Commission certifies that the Final Rule will not have a significant economic impact on a substantial number of small entities.

IX. Document Availability

1760. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (*http://www.ferc.gov*) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington DC 20426.

1761. From the Commission's Home Page on the Internet, this information is available in the Commission's document management system, eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type ''RM05–25'' or ''RM05–17'' in the docket number field.

1762. User assistance is available for eLibrary and the Commission's website during normal business hours. For assistance, please contact the Commission's Online Support at 1–866–208–3676 (toll free) or 202–502–6652 (e-mail at *FERCOnlineSupport@FERC.gov*), or the Public Reference Room at 202–502–8371, TTY 202–502–8659 (e-mail at *public.referenceroom@ferc.gov*).

X. Effective Date and Congressional Notification

1763. These regulations are effective May 14, 2007. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996. The Commission will submit the Final Rule to both houses of Congress and to the General Accounting Office.

List of Subjects

18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

18 CFR Part 37

Conflict of interests, Electric power plants, Electric utilities, Reporting and recordkeeping requirements.

By the Commission.

Magalie R. Salas,

Secretary.

■ In consideration of the foregoing, the Commission amends parts 35 and 37,

[1002] *Regulations Implementing the National Environmental Policy Act*, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. ¶ 30,783 (1987).

[1003] 18 CFR 380.4(a)(15).

[1004] 5 U.S.C. 601–612.

[1005] The Commission has identified 116 transmission providers with tariffs on file. We note that this figure is lower than our initial estimate in the NOPR, based on FERC Form No. 1 and FERC Form No. 1–F data.

[1006] *Id.*

[1007] The Regulatory Flexibility Act defines a ''small entity'' as ''one which is independently owned and operated and which is not dominant in its field of operation.'' *See* 5 U.S.C. 601(3) and 601(6); 15 U.S.C. 632(a)(1). In *Mid-Tex Elec. Coop.* v. *FERC*, 773 F.2d 327, 340–43 (D.C. Cir. 1985), the court accepted the Commission's conclusion that, since virtually all of the public utilities that it regulates do not fall within the meaning of the term ''small entities'' as defined in the Regulatory Flexibility Act, the Commission did not need to prepare a regulatory flexibility analysis in connection with its proposed rule governing the allocation of costs for construction work in progress (CWIP). The CWIP rules applied to all public utilities. The revised *pro forma* OATT will apply only to those public utilities that own, control or operate interstate transmission facilities. These entities are a subset of the group of public utilities found not to require preparation of a regulatory flexibility analysis for the CWIP rule.

Chapter I, Title 18 of the *Code of Federal Regulations*, as follows:

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

■ 1. The authority citation for part 35 continues to read as follows:

Authority: 16 U.S.C. 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 71–7352.

■ 2. Amend § 35.28 as follows:
■ a. Paragraph (c) is revised.
■ b. Paragraphs (d)(i) and (d)(ii) are redesignated as paragraphs (d)(1) and (d)(2).
■ c. Newly redesignated paragraph (d)(1) is revised.
■ d. Paragraph (e)(1) introductory text is revised.
■ e. Paragraph (e)(1)(ii) is revised.

§ 35.28 Non-discriminatory open access transmission tariff.

* * * * *

(c) *Non-discriminatory open access transmission tariffs.* (1) Every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce must have on file with the Commission a tariff of general applicability for transmission services, including ancillary services, over such facilities. Such tariff must be the open access pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036 (Final Rule on Open Access and Stranded Costs), as revised by the open access pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 (Final Rule on Open Access Reforms), or such other open access tariff as may be approved by the Commission consistent with Order No. 888, FERC Stats. & Regs ¶ 31,306 and Order No. 890, FERC Stats. & Regs. ¶ 31,241.

(i) Subject to the exceptions in paragraphs (c)(1)(ii), (c)(1)(iii), (c)(1)(iv) and (c)(1)(v) of this section, the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the open access pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241, and accompanying rates, must be filed no later than 60 days prior to the date on which a public utility would engage in a sale of electric energy at wholesale in interstate commerce or in the transmission of electric energy in interstate commerce.

(ii) If a public utility owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce as of May 14, 2007, it must file the revisions to the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Order No. 890, FERC Stats. & Regs ¶ 31,241.

(iii) If a public utility owns, controls, or operates transmission facilities used for the transmission of electric energy in interstate commerce as of May 14, 2007, such facilities are jointly owned with a non-public utility, and the joint ownership contract prohibits transmission service over the facilities to third parties, the public utility with respect to access over the public utility's share of the jointly owned facilities must file no later than May 14, 2007 the revisions to the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA.

(iv) Any public utility whose transmission facilities are under the independent control of a Commission-approved ISO or RTO may satisfy its obligation under paragraph (c)(1) of this section, with respect to such facilities, through the open access transmission tariff filed by the ISO or RTO.

(v) If a public utility obtains a waiver of the tariff requirement pursuant to paragraph (d) of this section, it does not need to file the pro forma tariff required by this section.

(vi) Any public utility that seeks a deviation from the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised in Order No. 890, FERC Stats. & Regs. ¶ 31,241, must demonstrate that the deviation is consistent with the principles of Order No. 888, FERC Stats. & Regs ¶ 31,036 and Order No. 890, FERC Stats. & Regs. ¶ 31,241.

(vii) Each public utility's open access transmission tariff must include the standards incorporated by reference in part 38 of this chapter.

(2) Subject to the exceptions in paragraphs (c)(2)(i) and (c)(3)(iii) of this section, every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce, and that uses those facilities to engage in wholesale sales and/or purchases of electric energy, or unbundled retail sales of electric energy, must take transmission service for such sales and/or purchases under the open access transmission tariff filed pursuant to this section.

(i) For sales of electric energy pursuant to a requirements service agreement executed on or before July 9, 1996, this requirement will not apply unless separately ordered by the Commission. For sales of electric energy pursuant to a bilateral economy energy coordination agreement executed on or before July 9, 1996, this requirement is effective on December 31, 1996. For sales of electric energy pursuant to a bilateral non-economy energy coordination agreement executed on or before July 9, 1996, this requirement will not apply unless separately ordered by the Commission.

(ii) [Reserved.]

(3) Every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce, and that is a member of a power pool, public utility holding company, or other multi-lateral trading arrangement or agreement that contains transmission rates, terms or conditions, must have on file a joint pool-wide or system-wide open access transmission tariff, which tariff must be the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241, or such other open access tariff as may be approved by the Commission consistent with Order No. 888, FERC Stats. & Regs. ¶ 31,036 and Order No. 890, FERC Stats. & Regs. ¶ 31,241.

(i) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed after May 14, 2007, this requirement is effective on the date that transactions begin under the arrangement or agreement.

(ii) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed on or before May 14, 2007, a public utility member of such power pool, public utility holding company or other multi-lateral arrangement or agreement that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce must file the revisions to its joint pool-wide or system-wide contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Order No. 890, FERC Stats. & Regs ¶ 31,241.

(iii) A public utility member of a power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed on or before July 9, 1996 must take transmission service under a joint pool-wide or system-wide open access transmission tariff filed pursuant to this section for wholesale trades among the pool or system members.

(4) Consistent with paragraph (c)(1) of this section, every Commission-approved ISO or RTO must have on file with the Commission a tariff of general applicability for transmission services, including ancillary services, over such facilities. Such tariff must be the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241, or such other open access tariff as may be approved by the Commission consistent with Order No. 888, FERC Stats. & Reg. ¶ 31,036 and Order No. 890, FERC Stats. & Regs. ¶ 31,241.

(i) Subject to paragraph (c)(4)(ii) of this section, a Commission-approved ISO or RTO must file the revisions to the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Order No. 890, FERC Stats. & Regs ¶ 31,241.

(ii) If a Commission-approved ISO or RTO can demonstrate that its existing open access tariff is consistent with or superior to the revisions to the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the pro forma tariff in Order No. 890, FERC Stats. & Regs. ¶ 31,241, or any portions thereof, the Commission-approved ISO or RTO may instead set forth such demonstration in its filing pursuant to section 206 in accordance with the procedures set forth in Order No. 890, FERC Stats. & Regs ¶ 31,241.

(d) *Waivers.* * * *

(1) No later than May 14, 2007, or

* * * * *

(e) *Non-public utility procedures for tariff reciprocity compliance.* (1) A non-public utility may submit a transmission tariff and a request for declaratory order that its voluntary transmission tariff meets the requirements of Order No. 888, FERC Stats. & Regs. ¶ 31,036 and Order No. 890, FERC Stats. & Regs. ¶ 31,241.

* * * * *

(ii) If the submittal is found to be an acceptable transmission tariff, an applicant in a Federal Power Act (FPA) section 211 or 211A proceeding against the non-public utility shall have the burden of proof to show why service under the open access tariff is not sufficient and why a section 211 or 211A order should be granted.

* * * * *

PART 37—OPEN ACCESS SAME-TIME INFORMATION SYSTEMS

■ 3. The authority citation for part 37 continues to read as follows:

Authority: 16 U.S.C. 791–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

■ 4. Amend § 37.6 as follows:
■ a. Paragraph (a)(1) is revised.
■ b. Paragraph (b) introductory text is revised.
■ c. Paragraphs (b)(1)(v) through (b)(1)(viii) are added.
■ d. Paragraphs (b)(2)(i) through (b)(2)(iii) are revised.
■ e. Paragraph (b)(3) is revised.
■ f. Paragraphs (c)(2) and (c)(5) are revised.
■ g. Paragraphs (e)(1) and (e)(2)(ii) are revised.
■ h. Paragraph (e)(3)(ii) is revised.
■ i. Paragraphs (h), (i) and (j) are added.

§ 37.6 Information to be posted on the OASIS.

(a) * * *

(1) Make requests for transmission services offered by Transmission Providers, Resellers and other providers of ancillary services, request the designation of a network resource, and request the termination of the designation of a network resource;

* * * * *

(b) *Posting transfer capability.* The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.

(1) * * *

(v) *Available transfer capability* or *ATC* means the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses, or such definition as contained in Commission-approved Reliability Standards.

(vi) *Total transfer capability* or *TTC* means the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions, or such definition as contained in Commission-approved Reliability Standards.

(vii) *Capacity Benefit Margin* or *CBM* means the amount of TTC preserved by the Transmission Provider for load-serving entities, whose loads are located on that Transmission Provider's system, to enable access by the load-serving entities to generation from interconnected systems to meet generation reliability requirements, or such definition as contained in Commission-approved Reliability Standards.

(viii) *Transmission Reliability Margin* or *TRM* means the amount of TTC necessary to provide reasonable assurance that the interconnected transmission network will be secure, or such definition as contained in Commission-approved Reliability Standards.

(2) * * *

(i) Information used to calculate any posting of ATC and TTC must be dated and time-stamped and all calculations shall be performed according to consistently applied methodologies referenced in the Transmission Provider's transmission tariff and shall be based on Commission-approved Reliability Standards as well as current industry practices, standards and criteria.

(ii) On request, the Responsible Party must make all data used to calculate ATC, TTC, CBM, and TRM for any constrained posted paths publicly available (including the limiting element(s) and the cause of the limit (*e.g.*, thermal, voltage, stability), as well as load forecast assumptions) in electronic form within one week of the posting. The information is required to be provided only in the electronic format in which it was created, along with any necessary decoding instructions, at a cost limited to the cost of reproducing the material. This information is to be retained for six months after the applicable posting period.

(iii) System planning studies, facilities studies, and specific network impact studies performed for customers or the Transmission Provider's own network resources are to be made publicly available in electronic form on request and a list of such studies shall be posted on the OASIS. A study is required to be provided only in the electronic format in which it was created, along with any necessary decoding instructions, at a cost limited to the cost of reproducing the material. These studies are to be retained for five years.

(3) *Posting.* The ATC, TTC, CBM, and TRM for all Posted Paths must be posted in megawatts by specific direction and in the manner prescribed in this subsection.

(i) *Constrained posted paths.*—(A) *For firm ATC and TTC.*

(*1*) The posting shall show ATC, TTC, CBM, and TRM for a 30-day period. For this period postings shall be: by the hour, for the current hour and the 168 hours next following; and thereafter, by the day. If the Transmission Provider charges separately for on-peak and off-peak periods in its tariff, ATC, TTC, CBM, and TRM will be posted daily for each period.

(*2*) Postings shall also be made by the month, showing for the current month and the 12 months next following.

(*3*) If planning and specific requested transmission studies have been done, seasonal capability shall be posted for the year following the current year and for each year following to the end of the planning horizon but not to exceed 10 years.

(B) *For non-firm ATC and TTC.* The posting shall show ATC, TTC, CBM and TRM for a 30-day period by the hour and days prescribed under paragraph (b)(3)(i)(A)(*1*) of this section and, if so requested, by the month and year as prescribed under paragraph (b)(3)(i)(A)(*2*) and (*3*) of this section. The posting of non-firm ATC and TTC shall show CBM as zero.

(C) *Updating posted information for constrained paths.*

(*1*) The capability posted under paragraphs (b)(3)(i)(A) and (B) of this section must be updated when transactions are reserved or service ends or whenever the estimate for the path changes by more than 10 percent.

(*2*) All updating of hourly information shall be made on the hour.

(*3*) When the monthly and yearly capability posted under paragraphs (b)(3)(i)(A) and (B) of this section are updated because of a change in TTC by more than 10 percent, the Transmission Provider shall post a brief, but specific, narrative explanation of the reason for the update. This narrative should include, the specific events which gave rise to the update (*e.g.*, scheduling of planned outages and occurrence of forced transmission outages, de-ratings of transmission facilities, scheduling of planned generation outages and occurrence of forced generation outages, changes in load forecast, changes in new facilities' in-service dates, or other events or assumption changes) and new values for ATC on the path (as opposed to all points on the network).

(*4*) When the monthly and yearly capability posted under paragraphs (b)(3)(i)(A) and (B) of this section remain unchanged at a value of zero for a period of six months, the Transmission Provider shall post a brief, but specific, narrative explanation of the reason for the unavailability of ATC.

(ii) *Unconstrained posted paths.*

(A) Postings of firm and nonfirm ATC, TTC, CBM, and TRM shall be posted separately by the day, showing for the current day and the next six days following and thereafter, by the month for the 12 months next following. If the Transmission Provider charges separately for on-peak and off-peak periods in its tariff, ATC, TTC, CBM, and TRM will be posted separately for the current day and the next six days following for each period. These postings are to be updated whenever the ATC changes by more than 20 percent of the Path's TTC.

(B) If planning and specific requested transmission studies have been done, seasonal capability shall be posted for the year following the current year and for each year following until the end of the planning horizon but not to exceed 10 years.

(iii) *Calculation of CBM.*

(A) The Transmission Provider must reevaluate its CBM needs at least every year.

(B) The Transmission Provider must post its practices for reevaluating its CBM needs.

(iv) *Daily load.* The Transmission Provider must post on a daily basis, its actual daily peak load for the prior day.

(c) * * *

(2) Transmission Providers must provide a downloadable file of their complete tariffs in the same electronic format as the tariff that is filed with the Commission. Transmission Providers also must provide a link to all of the rules, standards and practices that relate to transmission services posted on the Transmission Providers' public Web sites.

* * * * *

(5) Customers choosing to use the OASIS to offer for resale transmission capacity they have purchased must post relevant information to the same OASIS as used by the Transmission Provider from whom the Reseller purchased the transmission capacity. This information must be posted on the same display page, using the same tables, as similar capability being sold by the Transmission Provider, and the information must be contained in the same downloadable files as the Transmission Provider's own available capability.

* * * * *

(e) *Posting specific transmission and ancillary service requests and responses.*

(1) *General rules.*

(i) All requests for transmission and ancillary service offered by Transmission Providers under the *pro forma* tariff, including requests for discounts, and all requests to designate or terminate a network resource, must be made on the OASIS and posted prior to the Transmission Provider responding to the request, except as discussed in paragraphs (e)(1)(ii) and (iii) of this section. The Transmission Provider must post all requests for transmission service, for ancillary service, and for the designation or termination of a network resource comparably. Requests for transmission service, ancillary service, and to designate and terminate a network resource, as well as the responses to such requests, must be conducted in accordance with the Transmission Provider's tariff, the Federal Power Act, and Commission regulations.

(ii) The requirement in paragraph (e)(1)(i) of this section, to post requests for transmission and ancillary service offered by Transmission Providers under the *pro forma* tariff, including requests for discounts, prior to the Transmission Provider responding to the request, does not apply to requests for next-hour service made during Phase I.

(iii) In the event that a discount is being requested for ancillary services that are not in support of basic transmission service provided by the Transmission Provider, such request need not be posted on the OASIS.

(iv) In processing a request for transmission or ancillary service, the Responsible Party shall post the same information as required in paragraphs (c)(4) and (d)(3) of this section, and the following information: the date and time when the request is made, its place in any queue, the status of that request, and the result (accepted, denied, withdrawn). In processing a request to designate or terminate the designation of a network resource, the Responsible Party shall post the date and time when the request is made.

(v) For any request to designate or terminate a network resource, the Transmission Provider (at the time when the request is received), must post on the OASIS (and make available for download) information describing the request (including: name of requestor, identification of the resource, effective time for the designation or termination, identification of whether the transaction involves the Transmission Provider's wholesale merchant function or any affiliate; and any other relevant terms and conditions) and shall keep such information posted on the OASIS for at least 30 days. A record of the transaction must be retained and kept available as part of the audit log required in § 37.7.

(vi) The Transmission Provider shall post a list of its current designated network resources and all network customers' current designated network resources on OASIS. The list of network resources should include the name of the resource, its geographic and electrical location, its total installed capacity, and the amount of capacity to be designated as a network resource.

(2) * * *

(ii) Information to support the reason for the denial, including the operating status of relevant facilities, must be maintained for five years and provided, upon request, to the potential Transmission Customer and the Commission's Staff.

* * * * *

(3) * * *

(ii) Information to support any such curtailment or interruption, including the operating status of the facilities involved in the constraint or interruption, must be maintained and made available upon request, to the curtailed or interrupted customer, the Commission's Staff, and any other person who requests it, for five years.

* * * * *

(h) *Posting information summarizing the time to complete transmission service request studies.* (1) For each calendar quarter, the Responsible Party must post the set of measures detailed in paragraph (h)(1)(i) through paragraph (h)(1)(vi) of this section related to the Responsible Party's processing of transmission service request system impact studies and facilities studies. The Responsible Party must calculate and post the measures in paragraph (h)(1)(i) through paragraph (h)(1)(vi) of this section separately for requests for short-term firm point-to-point transmission service, long-term firm point-to-point transmission service, and requests to designate a new network resource and must be calculated and posted separately for transmission service requests from Affiliates and transmission service requests from Transmission Customers who are not Affiliates. The Responsible Party is required to include in the calculations of the measures in paragraph (h)(1)(i) through paragraph (h)(1)(vi) of this section all studies the Responsible Party conducts of transmission service requests on another Transmission Provider's OASIS.

(i) *Process time from initial service request to offer of system impact study agreement.*

(A) Number of new system impact study agreements delivered during the reporting quarter to entities that request transmission service,

(B) Number of new system impact study agreements delivered during the reporting quarter to entities that request transmission service more than thirty (30) days after the Responsible Party received the request for transmission service,

(C) Mean time (in days), for all requests acted on by the Responsible Party during the reporting quarter, from the date when the Responsible Party received the request for transmission service to when the Responsible Party changed the transmission service request status to indicate that the Responsible Party could offer transmission service or needed to perform a system impact study,

(D) Mean time (in days), for all system impact study agreements delivered by the Responsible Party during the reporting quarter, from the date when the Responsible Party received the request for transmission service to the date when the Responsible Party delivered a system impact study agreement, and

(E) Number of new system impact study agreements executed during the reporting quarter.

(ii) *System impact study processing time.*

(A) Number of system impact studies completed by the Responsible Party during the reporting quarter,

(B) Number of system impact studies completed by the Responsible Party during the reporting quarter more than 60 days after the Responsible Party received an executed system impact study agreement,

(C) For all system impact studies completed more than 60 days after receipt of an executed system impact study agreement, average number of days study was delayed due to transmission customer's actions (*e.g.*, delays in providing needed data),

(D) Mean time (in days), for all system impact studies completed by the Responsible Party during the reporting quarter, from the date when the Responsible Party received the executed system impact study agreement to the date when the Responsible Party provided the system impact study to the entity who executed the system impact study agreement, and

(E) Mean cost of system impact studies completed by the Responsible Party during the reporting quarter.

(iii) *Transmission service requests withdrawn from the system impact study queue.*

(A) Number of transmission service requests withdrawn from the Responsible Party's system impact study queue during the reporting quarter,

(B) Number of transmission service requests withdrawn from the Responsible Party's system impact study queue during the reporting quarter more than 60 days after the Responsible Party received the executed system impact study agreement, and

(C) Mean time (in days), for all transmission service requests withdrawn from the Responsible Party's system impact study queue during the reporting quarter, from the date the Responsible Party received the executed system impact study agreement to date when request was withdrawn from the Responsible Party's system impact study queue.

(iv) *Process time from completed system impact study to offer of facilities study.*

(A) Number of new facilities study agreements delivered during the reporting quarter to entities that request transmission service,

(B) Number of new facilities study agreements delivered during the reporting quarter to entities that request transmission service more than thirty (30) days after the Responsible Party completed the system impact study,

(C) Mean time (in days), for all facilities study agreements delivered by the Responsible Party during the reporting quarter, from the date when the Responsible Party completed the system impact study to the date when the Responsible Party delivered a facilities study agreement, and

(D) Number of new facilities study agreements executed during the reporting quarter.

(v) *Facilities study processing time.*

(A) Number of facilities studies completed by the Responsible Party during the reporting quarter,

(B) Number of facilities studies completed by the Responsible Party during the reporting quarter more than 60 days after the Responsible Party received an executed facilities study agreement,

(C) For all facilities studies completed more than 60 days after receipt of an executed facilities study agreement, average number of days study was delayed due to transmission customer's actions (*e.g.*, delays in providing needed data),

(D) Mean time (in days), for all facilities studies completed by the Responsible Party during the reporting quarter, from the date when the Responsible Party received the executed facilities study agreement to the date when the Responsible Party provided the facilities study to the entity who executed the facilities study agreement,

(E) Mean cost of facilities studies completed by the Responsible Party during the reporting quarter, and

(F) Mean cost of upgrades recommended in facilities studies completed during the reporting quarter.

(vi) *Service requests withdrawn from facilities study queue.*

(A) Number of transmission service requests withdrawn from the Responsible Party's facilities study queue during the reporting quarter,

(B) Number of transmission service requests withdrawn from the

Responsible Party's facilities study queue during the reporting quarter more than 60 days after the Responsible Party received the executed facilities study agreement, and

(C) Mean time (in days), for all transmission service requests withdrawn from the Responsible Party's facilities study queue during the reporting quarter, from the date the Responsible Party received the executed facilities study agreement to date when request was withdrawn from the Responsible Party's facilities study queue.

(2) The Responsible Party is required to post the measures in paragraph (h)(1)(i) through paragraph (h)(1)(vi) of this section for each calendar quarter within 15 days of the end of the calendar quarter. The Responsible Party will keep the quarterly measures posted on OASIS for three calendar years.

(3) The Responsible Party will be required to post on OASIS the measures in paragraph (h)(3)(i) through paragraph (h)(3)(iv) of this section in the event the Responsible Party, for two consecutive calendar quarters, completes more than twenty (20) percent of the studies associated with requests for transmission service from entities that are not Affiliates of the Responsible Party more than sixty (60) days after the Responsible Party delivers the appropriate study agreement. The Responsible Party will have to post the measures in paragraph (h)(3)(i) through paragraph (h)(3)(iv) of this section until it processes at least ninety (90) percent of all studies within 60 days after it has received the appropriate executed study agreement. For the purposes of calculating the percent of studies completed more than sixty (60) days after the Responsible Party delivers the appropriate study agreement, the Responsible Party should aggregate all system impact studies and facilities studies that it completes during the reporting quarter. The Responsible Party must calculate and post the measures in paragraph (h)(3)(i) through paragraph (h)(3)(iv) of this section separately for requests for short-term firm point-to-point transmission service, long-term firm point-to-point transmission service, and requests to designate a new network resource and must be calculated and posted separately for transmission service requests from Affiliates and transmission service requests from Transmission Customers who are not Affiliates.

(i) Mean, across all system impact studies the Responsible Party completes during the reporting quarter, of the employee-hours expended per system impact study the Responsible Party completes during reporting period;

(ii) Mean, across all facilities studies the Responsible Party completes during the reporting quarter, of the employee-hours expended per facilities study the Responsible Party completes during reporting period;

(iii) The number of employees the Responsible Party has assigned to process system impact studies;

(iv) The number of employees the Responsible Party has assigned to process facilities studies.

(4) The Responsible Party is required to post the measures in paragraph (h)(3)(i) through paragraph (h)(3)(iv) of this section for each calendar quarter within 15 days of the end of the calendar quarter. The Responsible Party will keep the quarterly measures posted on OASIS for five calendar years.

(i) *Posting data related to grants and denials of service.* The Responsible Party is required to post data each month listing, by path or flowgate, the number of transmission service requests that have been accepted and the number of transmission service requests that have been denied during the prior month. This posting must distinguish between the length of the service request (*e.g.*, short-term or long-term requests) and between the type of service requested (*e.g.*, firm point-to-point, non-firm point-to-point or network service). The posted data must show:

(1) The number of non-Affiliate requests for transmission service that have been rejected,

(2) The total number of non-Affiliate requests for transmission service that have been made,

(3) The number of Affiliate requests for transmission service that have been rejected, and

(4) The total number of Affiliate requests for transmission service that have been made.

(j) *Posting redispatch data.*

(1) The Transmission Provider must allow the posting on OASIS of any third party offer to relieve a specified congested transmission facility.

(2) The Transmission Provider must post on OASIS (i) its monthly average cost of planning and reliability redispatch, for which it invoices customers, at each internal transmission facility or interface over which it provides redispatch service and (ii) a high and low redispatch cost for the month for each of these same transmission facilities. The transmission provider must post this data on OASIS as soon as practical after the end of each month, but no later than when it sends invoices to transmission customers for redispatch-related services.

■ 5. In § 37.7, paragraph (b) is revised to read as follows:

§ 37.7 Auditing Transmission Service Information.

* * * * *

(b) Audit data must remain available for download on the OASIS for 90 days, except ATC/TTC postings that must remain available for download on the OASIS for 20 days. The audit data are to be retained and made available upon request for download for five years from the date when they are first posted in the same electronic form as used when they originally were posted on the OASIS.

Note: The following appendices will not be published in the *Code of Federal Regulations.*

Appendix A: Summary of Compliance Filing Requirements

For a more detailed description of compliance obligations please refer to the Final Rule paragraph number. For further information related to the Final Rule, such as electronic versions of the *pro forma* OATT showing tariff changes adopted in the Final Rule in redline/strikeout format, and further information regarding docketing of compliance filings and specific filing instructions, please visit our Web site at the following location *http://www.ferc.gov/industries/electric/indus-act/oatt-reform.asp.*

Deadline (days after publication in Federal Register)	Compliance action	Final rule paragraph No.
30	Optional Implementation FPA section 205 filings allowing transmission providers to propose previously approved variations from the *pro forma* OATT that have been affected by *pro forma* OATT Final Rule reforms to remain in effect subject to a demonstration that such variations continue to be consistent with or superior to the revised Final Rule *pro forma* OATT (non RTO/ISO transmission providers). Such optional filings must request a 90 day effective date to facilitate Commission review under section 205.	P 139

Deadline (days after publication in Federal Register)	Compliance action	Final rule paragraph No.
60	Non-ISO/RTO transmission providers submit FPA section 206 filings that contain the non-rate terms and conditions set forth in Final Rule. These filings need only contain the revised provisions adopted in the Final Rule. Transmission providers utilizing the optional Implementation FPA section 205 filing described above, need only submit tariff sheets necessary to implement the remaining modifications required under the Final Rule, *i.e.*, modifications related to tariff provisions that did not implicate previously-approved variations.	P 135
75	Transmission Providers must post a "strawman" proposal for compliance with each of the nine planning principles adopted in the Final Rule. This may be posted on the Transmission Providers Web site or its OASIS site.	P 443
90	NERC/NAESB status report and work plan for completion of ATC related business practices and standards.	P 223
	NAESB status report and work plan for completion of OASIS functionality or uniform business practices (other than those related to ATC).	P 141
120	Transmission Providers must submit redesigned transmission charges that reflect the Capacity Benefit Margin set-aside through a limited issue section 205 rate filing as part of their initial ATC related compliance filings.	P 263
180	Submit compliance filings with Attachment C (ATC) of the *pro forma* OATT	P 140
210	ISOs and RTOs, and transmission providers located within an ISO/RTO footprint, submit FPA section 206 filings that contain the non-rate terms and conditions set forth in the Final Rule. These filings need only contain the revised provisions adopted in the Final Rule or a demonstration that previously approved variations continue to be consistent with or superior to the revised *pro forma* OATT.	P 157, P 161
210	Submit compliance filings with Attachment K (Planning) of the *pro forma* OATT or RTOs and ISOs file a demonstration that their planning processes are consistent with or superior to the planning principles in the Final Rule.	P 140, P 442
N/A	Transmission Providers must file a revised Attachment C to incorporate any changes to NERC's and NAESB's reliability and business practice standards to achieve consistency in ATC within 60 days of completion of the NERC and NAESB processes.	P 325
N/A	After the submission of FPA section 206 compliance filings, transmission providers may submit FPA section 205 filings proposing rates for the services provided for in the tariff, as well as non-rate terms and conditions that differ from those set forth in the Final Rule if those provisions are "consistent with or superior to" the *pro forma* OATT.	P 135

Appendix B: Commenting Party Acronyms

INITIAL COMMENTERS

Abbreviation	Initial commenters
Alberta Intervenors	Alberta Intervenors (TransCanada Energy Ltd., ENMAX Energy Marketing, Inc.; EPCOR Merchant and Capital, LP; and TransAlta Corporation).
Alcoa	Alcoa Inc. and Alcoa Power Generating Inc.
Allegheny	Allegheny Power and Allegheny Energy Supply Company, LLC.
Ameren	Ameren Services Company.
American Transmission	American Transmission Company LLC.
AMP-Ohio	American Municipal Power-Ohio, Inc.
Anaheim	Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California.
APPA	American Public Power Association.
ARC	Alliance for Retail Choice.
Arkansas Commission	Arkansas Public Service Commission.
Arkansas Municipal	Arkansas Municipal Power Association.
AWEA	American Wind Energy Association.
Barrick	Barrick Goldstrike Mines Inc.
BART	San Francisco Bay Area Rapid Transit District.
Bonneville	Bonneville Power Administration.
BP Energy	BP Energy Company.
Bureau of Reclamation	U.S. Bureau of Reclamation.
CAC/EPUC	Cogeneration Association of California (Coalinga Cogeneration Co., Mid-Set Cogeneration Co., Kern River Cogeneration Co., Sycamore Cogeneration Co., Sargent Canyon Cogeneration Co., Salinas River Cogeneration Co., Midwest Sunset Cogeneration Co. and Watson Cogeneration Co.) and Energy Producers and Users Coalition (Aera Energy LLC, BP American, Inc., Chevron USA, Inc., ConocoPhilips Co., ExxonMobil Power and Gas Services, Inc., Shell Oil Products, US, THUMS Long Beach Co., Occidental Elk Hills, Inc., and Valero Refining Co.—California).
CAISO	California Independent System Operator Corporation.
California Commission	Public Utilities Commission of the State of California.
Calpine	Calpine Corporation.
Chandley-Hogan	John D. Chandley and William W. Hogan.

INITIAL COMMENTERS—Continued

Abbreviation	Initial commenters
ColumbiaGrid	ColumbiaGrid Members (Bonneville Power Administration; Avista Corp.; Public Utility District No. 1 of Chelan County, Washington; Public Utility District No. 2 of Grant County, Washington; Puget Sound Energy, Inc.; Seattle City Light; and Tacoma Power.
Community Power Alliance	Community Power Alliance Members (Entergy, Progress Energy, Salt River Project Agricultural Improvement and Power District, and Southern Co.).
Constellation	Constellation Energy Group, Inc.
CREPC	Committee on Regional Electric Power Corp.
Dominion	Dominion Resources Services, Inc. (Armstrong Energy Limited Partnership, LLLP; Dominion Energy Marketing, Inc.; Elwood Energy, LLC; Fairless Energy, LLC; Pleasants Energy, LLC and Virginia Electric and Power Co. d/b/a Dominion Virginia Power).
Dow	Dow Chemical Corp.
Duke	Duke Energy Corp.
E.ON	E.ON U.S. LLC.
East Texas Cooperatives	East Texas Electric Cooperative, Inc.; Northeast Texas Electric Cooperative, Inc.; Sam Rayburn Generation and Electric Cooperative, Inc. and Tex-La Electric Cooperative of Texas, Inc.
Eastern North Carolina	Eastern NC Towns (Towns of Black Creek, NC; Lucama, NC; Stantonsburg, NC).
EEI	Edison Electric Institute.
ELCON	Electricity Consumers Resource Council, American Iron and Steel Institute, and American Forest & Paper Institute.
Emerald	Emerald People's Utility District.
Entegra	Entegra Power Group LLC and LS Power Associates, L.P.
Entergy	Entergy Services, Inc.
EPSA	Electric Power Supply Association.
Exelon	Exelon Corporation.
Fayetteville	Public Works Commission of the City of Fayetteville, North Carolina.
Fertilizer Institute	Fertilizer Institute.
FirstEnergy	FirstEnergy Service Company (First Energy Solutions; American Transmission Systems, Inc.; Jersey Central Power and Light Co.; Metropolitan Edison Co.; and Pennsylvania Electric Co.).
Flathead	Flathead Electric Cooperative.
Florida Commission	Florida Public Service Commission.
Florida Industrial Cogeneration Association	Florida Industrial Cogeneration Association.
FMPA	Florida Municipal Power Agency and Midwest Municipal Transmission Group.
Geothermal Producers	CE Generation, LLC; Ormat Technologies, Inc.; Caithness Energy, LLC; and Geothermal Energy Association.
Grant	Grant County PUD, Chelan County PUD and Pend Oreille County PUD.
Great Northern	Great Northern Power Development, L.P.
Imperial	Imperial Irrigation District.
Indianapolis Power	Indianapolis Power & Light Co.
Indicated New York Transmission Owners	Central Hudson Gas & Electric Corp.; Consolidated Edison Co. of New York, Inc.; LIPA; New York Power Authority; New York State Electric & Gas Corp.; Orange and Rockland Utilities, Inc.; and Rochester Gas and Electric Corp.
International Transmission	International Transmission Co. d/b/a ITC*Transmission* and Michigan Electric Transmission Co., LLC.
IRH Management	IRH Management Committee and the Schedule 20A Service Providers.
ISO New England	ISO New England, Inc. and New England Power Pool.
ISO/RTO Council	ISO/RTO Council.
Lassen	Lassen Municipal Utility District.
LDWP	City of Los Angeles Department of Water and Power.
LPPC	Large Public Power Council.
Manitoba Hydro	Manitoba Hydro.
MDEA	Mississippi Delta Energy Agency, Clarksdale Public Utilities Commission, and Public Service Commission of Yazoo City.
MidAmerican	MidAmerican Energy Company and PacifiCorp.
MISO	Midwest Independent Transmission System Operator, Inc.
MISO Transmission Owners	Midwest ISO Transmission Owners.
MISO/PJM States	Organization of MISO States and Organization of PJM States, Inc.
Morgan Stanley	Morgan Stanley Capital Group Inc.
NAESB	North American Energy Standards Board.
NARUC	National Association of Regulatory Utility Commissioners.
National Grid	National Grid USA.
NCEMC	North Carolina Electric Membership Corporation.
NCPA	Northern California Power Agency.
NERC	North American Electric Reliability Corporation.
Nevada Commission	Public Utilities Commission of Nevada.
Nevada Companies	Nevada Power Company and Sierra Pacific Power Company.
New Jersey Board	New Jersey Board of Public Utilities.
New Mexico Attorney General	New Mexico Attorney General.
New York Commission	New York State Public Service Commission.

INITIAL COMMENTERS—Continued

Abbreviation	Initial commenters
Newfoundland	Newfoundland and Labrador Hydro.
Newmont Mining	Newmont USA Limited, dba Newmont Mining Corp.
Northeast Utilities	Northeast Utilities Service Company (Connecticut Light and Power Co.; Western Massachusetts Electric Co.; Public Service Co. of New Hampshire; Holyoke Water Power Co.; and Holyoke Power and Electric Co.).
Northwest IOUs	Northwest Investor-Owned Utilities (Avista Corp., Portland General Electric Co., and Puget Sound Energy, Inc.).
Northwest Parties	Northwest Parties (Avista Corp., Bonneville Power Administration, PacifiCorp, PNGC Power, Portland General Electric Co., Public Power Council, Public Utility Commission of Oregon and Puget Sound Energy, Inc.).
NorthWestern	NorthWestern Corporation.
NPPD	Nebraska Public Power District.
NRECA	National Rural Electric Cooperative Association.
NRG	NRG Energy, Inc.
NYAPP	New York Association of Public Power.
Occidental	Occidental Chemical Corporation.
Oklahoma Commission	Oklahoma Corporation Commission.
Old Dominion	Old Dominion Electric Cooperative.
Oversight Resources	Oversight Resources, LLC.
PGP	Public Generating Pool and Chelan County PUD.
Pinnacle	Pinnacle West Capital Corporation; Arizona Public Service Company; and APS Energy Services Company, Inc.
PJM	PJM Interconnection, LLC.
PNM–TNMP	Public Service Company of New Mexico and Texas-New Mexico Power Company.
Powerex	Powerex Corp.
PPL	PPL Companies.
PPM	PPM Energy, Inc.
Progress Energy	Progress Energy, Inc. (Carolina Power & Light Co. d/b/a Progress Energy Carolinas and Florida Power Corp., d/b/a Progress Energy Florida; and Progress Ventures, Inc.).
Project for Sustainable FERC Energy Policy	Project for Sustainable FERC Energy Policy (American Wind Energy Association, Delaware Division of the Public Advocate, Environmental Law & Policy Center, Illinois Citizens Utility Board, Natural Resources Defense Council, Northwest Energy Coalition, Office of the Ohio Consumers' Counsel, Pace Energy Project, Project for Sustainable FERC Energy Policy, Renewable Northwest Project, West Wind Wires, and Wind on the Wires).
PSEG	Public Service Electric and Gas Company; PSEG Power LLC; and PSEC Energy Resources & Trade LLC (PSEG Companies).
Public Power Council	Public Power Council.
Reliant	Reliant Energy, Inc.
Sacramento	Sacramento Municipal Utility District.
Salt River	Salt River Project Agricultural Improvement and Power District.
San Diego G&E	San Diego Gas & Electric Company.
Santa Clara	City of Santa Clara, California d/b/a Silicon Valley Power.
Santee Cooper	South Carolina Public Service Authority.
SCE	Southern California Edison.
Seattle	City of Seattle—City Light Department.
Sempra Global	Sempra Global.
South Carolina E&G	South Carolina Electric & Gas Company.
South Carolina Regulatory Staff	South Carolina Office of Regulatory Staff.
Southern	Southern Company Services, Inc.
Southwest Transmission	Southwest Area Transmission Sub-Regional Planning Group.
Southwestern Coop	Southwestern Electric Cooperative, Inc.
SPP	Southwest Power Pool, Inc.
Steel Manufacturers Association	Steel Manufacturers Association.
Suez Energy NA	Suez Energy North America, Inc.
Tacoma	Tacoma Power.
TANC	Transmission Agency of Northern California.
TAPS	Transmission Access Policy Study Group.
TDU Systems	Transmission Dependent Utilities Systems.
TransAlta	TransAlta Energy Marketing (US) Inc.
TranServ	TranServ International, Inc.
Tucson	Tucson Electric Power Company.
TVA	Tennessee Valley Authority.
Utah Municipals	Utah Associated Municipal Power Systems.
WAPA	Western Area Power Administration.
WECC	Western Electricity Coordinating Council.
WestConnect	WestConnect Companies.
Western Governors	Western Governors' Association.
Williams	Williams Power Company, Inc.
Wisconsin Electric	Wisconsin Electric Power Company.
WSPP	Western Systems Power Pool, Inc.

INITIAL COMMENTERS—Continued

Abbreviation	Initial commenters
Xcel	Xcel Energy Services, Inc.

REPLY COMMENTERS

Abbreviation	Reply commenters
Alberta Intervenors	Alberta Intervenors (TransCanada Energy Ltd., ENMAX Energy Marketing, Inc.; EPCOR Merchant and Capital, LP; and TransAlta Corporation).
Anaheim	Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California.
APPA	American Public Power Association.
Barrick	Barrick Goldstrike Mines Inc.
Bonneville	Bonneville Power Administration.
CAISO	California Independent System Operator Corporation.
California Commission	Public Utilities Commission of the State of California.
Canadian Electricity Association	Canadian Electricity Association.
Chandley-Hogan	John D. Chandley and William W. Hogan.
CMUA	California Municipal Utilities Association.
ColumbiaGrid	ColumbiaGrid Members (Bonneville Power Administration; Avista Corp.; Public Utility District No. 1 of Chelan County, Washington; Public Utility District No. 2 of Grant County, Washington; Puget Sound Energy, Inc.; Seattle City Light; and Tacoma Power.
Community Power Alliance	Community Power Alliance Members (Entergy, Progress Energy, Salt River Project Agricultural Improvement and Power District, and Southern Co.).
Detroit Edison	Detroit Edison Co.
Duke	Duke Energy Corp.
Dynegy	Dynegy Power Marketing, Inc.
East Texas Cooperatives	East Texas Electric Cooperative, Inc.; Northeast Texas Electric Cooperative, Inc.; Sam Rayburn Generation and Electric Cooperative, Inc. and Tex-La Electric Cooperative of Texas, Inc.
EEI	Edison Electric Institute.
ElectriCities	ElectriCities of North Carolina, Inc.
Entegra	Entegra Power Group LLC and LS Power Associates, L.P.
Entergy	Entergy Services, Inc.
EPSA	Electric Power Supply Association.
Exelon	Exelon Corporation.
Fayetteville	Public Works Commission of the City of Fayetteville, North Carolina.
Fertilizer Institute	Fertilizer Institute.
FMPA	Florida Municipal Power Agency and Midwest Municipal Transmission Group.
Great Northern	Great Northern Power Development, L.P.
Hoosier	Hoosier Energy Rural Electric Cooperative, Inc.
H.Q. Energy	H.Q. Energy Services (U.S.), Inc.
Indianapolis Power	Indianapolis Power & Light Co.
Industrial Customers of Northwest Utilities	Industrial Customers of Northwest Utilities (Air Liquide; Air Products; BPB Gypsum, Inc.; Blue Heron Paper Company; Boeing; Boise Cascade; CNC Containers, Northwest; Chemi-Con Materials Corporation; Dyno Nobel, Inc.; ConAgra Foods; Eka Chemicals, Inc.; Evanite Fiber; Georgia-Pacific; Grays Harbor Paper, L.P.; Hewlett-Packard; Inland Empire Paper Co.; Intel; J.R. Simplot; Kimberly-Clark Corporation; Longview Fibre; Microsoft Corporation; Norpac Foods; Noveon Kalama, Inc.; Oregon Steel Mills; PCC Structurals, Inc.; Ponderay Newsprint Co; Shell Oil Products US; Simpson Paper; Simpson Timber; Solar Grade Silicon LLC; SP Newsprint Co.; Tesoro Refining and Marketing Co.; Wah Chang; West Linn Paper Company; Weyerhaeuser).
International Transmission	International Transmission Co. d/b/a ITC*Transmission* and Michigan Electric Transmission Co., LLC.
ISO/RTO Council	ISO/RTO Council.
Lassen	Lassen Municipal Utility District.
LPPC	Large Public Power Council.
MAPP	Mid-Continent Area Power Pool.
Mark Lively	Mark B. Lively.
MDEA	Mississippi Delta Energy Agency, Clarksdale Public Utilities Commission, Public Service Commission of Yazoo City, Arkansas Electric Cooperative Corporation, Municipal Energy Agency of Mississippi, and Lafayette Utilities System*.[1008]
MidAmerican	MidAmerican Energy Company and PacifiCorp.
MISO	Midwest Independent Transmission System Operator, Inc.
Morgan Stanley	Morgan Stanley Capital Group Inc.
NARUC	National Association of Regulatory Utility Commissioners.
NC Transmission Planning Participants	North Carolina Transmission Planning Collaborative Participants.
NCPA	Northern California Power Agency.
Newmont Mining	Newmont USA Limited, dba Newmont Mining Corp.
North Carolina Commission	North Carolina Utilities Commission; Public Staff of the North Carolina Utilities Commission; and the Attorney General of the State of North Carolina.

REPLY COMMENTERS—Continued

Abbreviation	Reply commenters
Northwest IOUs	Northwest Investor-Owned Utilities (Avista Corp., Portland General Electric Co., and Puget Sound Energy, Inc.).
NorthWestern	NorthWestern Corporation.
NRECA	National Rural Electric Cooperative Association.
Occidental	Occidental Chemical Corporation.
OG&E	Oklahoma Gas and Electric Company.
Ohio Power Siting Board	Ohio Power Siting Board, American Municipal Power-Ohio, Inc. and Buckeye Power, Inc.
Old Dominion	Old Dominion Electric Cooperative; Southern Maryland Electric Cooperative, Inc.; Allegheny Electric Cooperative, Inc.; and North Carolina Electric Membership Corporation.
Omaha Public Power	Omaha Public Power District.
Pennsylvania Commission	Pennsylvania Public Utility Commission.
PJM	PJM Interconnection, LLC.
PNM-TNMP	Public Service Company of New Mexico and Texas-New Mexico Power Company.
Powerex	Powerex Corp.
PPM	PPM Energy, Inc.
Progress Energy	Progress Energy, Inc. (Carolina Power & Light Co. d/b/a Progress Energy Carolinas and Florida Power Corp., d/b/a Progress Energy Florida; and Progress Ventures, Inc.).
Project for Sustainable FERC Energy Policy	Project for Sustainable FERC Energy Policy (Delaware Division of the Public Advocate, Environmental Law & Policy Center, Fresh Energy, Natural Resources Defense Council, Northwest Energy Coalition, Pace Energy Project, Project for Sustainable FERC Energy Policy, Renewable Northwest Project, West Wind Wires, and Wind on the Wires).*
Public Power Council	Public Power Council.
Sacramento	Sacramento Municipal Utility District.
Salt River	Salt River Project Agricultural Improvement and Power District.
Santa Clara	City of Santa Clara, California d/b/a Silicon Valley Power.
Seattle	City of Seattle—City Light Department.
Seminole	Seminole Electric Cooperative, Inc.
South Carolina E&G	South Carolina Electric & Gas Company.
Southern	Southern Company Services, Inc.
SPP	Southwest Power Pool, Inc.
Steel Manufacturers Association	Steel Manufacturers Association.
Strategic Energy	Strategic Energy, L.L.C.
TANC	Transmission Agency of Northern California.
TAPS	Transmission Access Policy Study Group.
TDU Systems	Transmission Dependent Utilities Systems.
Transparent Dispatch Advocates	PJM Interconnection, LLC; Electric Consumers Resource Council; Electric Power Supply Association; Natural Resources Defense Council; Renewable Northwest Project; Project for Sustainable FERC Energy Policy; Center for Energy Efficiency & Renewable Technologies; Shell Trading Gas and Power Company; American Wind Energy Association; and Exelon.
Utah Municipals	Utah Associated Municipal Power Systems.
WestConnect	WestConnect Companies.
Williams	Williams Power Company, Inc.
Wolverine	Wolverine Power Supply Cooperative, Inc.
WPS Companies	WPS Companies (Wisconsin Public Service Corporation and Upper Peninsula Power Company).
WSPP	Western Systems Power Pool, Inc.
Xcel	Xcel Energy Services, Inc.

TECHNICAL CONFERENCE COMMENTERS

Abbreviation	Technical conference commenters
APPA*	American Public Power Association.
APS*	Arizona Public Service Company.
Bonneville*	Bonneville Power Administration.
Constellation*	Constellation Energy Group, Inc.
EEI*	Exelon Corporation on behalf of Edison Electric Institute (EEI).
EPSA*[1009]	Electric Power Supply Association.
Exelon*	Exelon.
NAESB*	North American Energy Standards Board.
NARUC*	National Association of Regulatory Utility Commissioners.
National Grid*	National Grid USA.
National Grid/Central Hudson	National Grid USA, Central Hudson Gas & Electric Corporation, and American Wind Energy.
NERC*	Prague Power, LLC, on behalf of the North American Electric Reliability Corporation.

TECHNICAL CONFERENCE COMMENTERS—Continued

Abbreviation	Technical conference commenters
New York Parties	Consolidated Edison Co. of New York, Inc., Orange and Rockland Utilities, Inc., New York Power Authority, and Independent Power Producers of New York, Inc.
NRECA*	Great River Energy on behalf of National Rural Electric Cooperative Association (NRECA).
NRG on behalf of EPSA*	NRG Energy, Inc. on behalf of Electric Power Supply Association (EPSA).
PacifiCorp	PacifiCorp.
PJM*	PJM Interconnection, LLC.
AWEA*	PPM Energy, Inc. on behalf of American Wind Energy Association
Progress Energy*	Progress Energy, Inc. (Carolina Power & Light Company, d/b/a. Progress Energy Carolinas, Inc. and Florida Power Corporation, d/b/a Progress Energy Florida, Inc.).
Renewable Northwest Project*	Renewable Northwest Project.
San Diego G&E	San Diego Gas & Electric Company.
TAPS*	Southern Minnesota Municipal Power Agency and Transmission Access Policy Study Group.
TDU Systems	Transmission Dependent Utilities Systems.
South Carolina Regulatory Staff	South Carolina Office of Regulatory Staff.
Southern*	Southern Company Services, Inc.
WECC*	Western Electricity Coordinating Council.
Williams*	Williams Power.
Williams*	Williams Power Company, Inc.
Xcel*	Xcel Energy Services, Inc.

SUPPLEMENTAL COMMENTERS

Abbreviation	Supplemental commenters
Alabama Commission	Alabama Public Service Commission.
Ameren	Ameren Services Company.
APPA	American Public Power Association.
Barrick	Barrick Goldstrike Mines Inc.
Bonneville	Bonneville Power Administration.
BP Energy	BP Energy Company.
California Commission	Public Utilities Commission of the State of California.
Community Power Alliance	Community Power Alliance Members (Entergy, Progress Energy, Salt River Project Agricultural Improvement and Power District, and Southern Co.).
Constellation	Constellation Energy Group, Inc.
Duke	Duke Energy Corp.
E.ON	E.ON U.S. LLC.
EEI	Edison Electric Institute.
Entergy	Entergy Services, Inc.
EPSA and AWEA	Electric Power Supply Association and American Wind Energy Association.
Florida Commission	Florida Public Service Commission.
Georgia Commission	Georgia Public Service Commission.
LPPC	Large Public Power Council.
Mark Lively	Mark B. Lively.
MISO	Midwest Independent Transmission System Operator, Inc.
Nevada Companies	Nevada Power Company and Sierra Pacific Power Company.
North Carolina Commission	North Carolina Utilities Commission; Public Staff of the North Carolina Utilities Commission; and the Attorney General of the State of North Carolina.
NRECA	National Rural Electric Cooperative Association.
OG&E	Oklahoma Gas and Electric Company.
Pacific Coast Parties	Pacific Coast Parties (Avista Corporation, Bonneville Power Administration, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc., the Sacramento Municipal Utility District and the Transmission Agency of Northern California).
PGP	Public Generating Pool.
Southwest Utilities	Pinnacle West Companies, Public Service Company of New Mexico, Texas-New Mexico Power Company, and UniSource Energy Corporation.
PNM-TNMP	Public Service Company of New Mexico and Texas-New Mexico Power Company.
Powerex	Powerex Corp.
PPL	PPL Companies.
PPM	PPM Energy, Inc.
Progress Energy	Progress Energy, Inc. (Carolina Power & Light Company, d/b/a. Progress Energy Carolinas, Inc. and Florida Power Corporation, d/b/a Progress Energy Florida, Inc.).
Progress Energy and MidAmerican	Progress Energy, Inc. and MidAmerican Energy Company.
Public Power Council	Public Power Council.
SEARUC	Southeastern Association of Regulatory Utility Commissioners.
South Carolina E&G	South Carolina Electric & Gas Company.
South Carolina Regulatory Staff	South Carolina Office of Regulatory Staff.

SUPPLEMENTAL COMMENTERS—Continued

Abbreviation	Supplemental commenters
Southern	Southern Company Services, Inc.
Tacoma	Tacoma Power.
TAPS	Transmission Access Policy Study Group.
TDU Systems	Transmission Dependent Utilities Systems.
Transparent Dispatch Advocates	Transparent Dispatch Advocates (American Wind Energy Association; Center for Energy Efficiency & Renewable Technologies; Electric Consumers Resource Council; Electric Power Supply Association; Exelon Corporation; Natural Resources Defense Council; PJM Interconnection, LLC; PPM Energy; Project for Sustainable FERC Energy Policy; Renewable Northwest Project; and Shell Trading Gas and Power Company)*[1010]
Western Governors	Western Governors' Association.
Williams	Williams Power Company, Inc.
WIRES	WIRES.
Xcel	Xcel Energy Services, Inc.

Appendix C: Pro Forma Open Access Transmission Tariff

Table of Contents

[1008] A "*" indicates that the composition of this group has altered in the reply comment filing.

[1009] A "*" indicates that this party submitted speaker materials at the October 12 Technical Conference.

[1010] A "*" indicates that the composition of this group has altered in this filing.

I. Common Service Provisions

1 Definitions

1.1 Affiliate

With respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

1.2 Ancillary Services

Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

1.3 Annual Transmission Costs

The total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H until amended by the Transmission Provider or modified by the Commission.

1.4 Application

A request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

1.5 Commission

The Federal Energy Regulatory Commission.

1.6 Completed Application

An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

1.7 Control Area

An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

1. Match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
2. Maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
3. Maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and
4. Provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.8 Curtailment

A reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

1.9 Delivering Party

The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.10 Designated Agent

Any entity that performs actions or functions on behalf of the Transmission Provider, an Eligible Customer, or the Transmission Customer required under the Tariff.

1.11 Direct Assignment Facilities

Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

1.12 Eligible Customer

i. Any electric utility (including the Transmission Provider and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider offer the unbundled transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider.

ii. Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider offer the transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider, is an Eligible Customer under the Tariff.

1.13 Facilities Study

An engineering study conducted by the Transmission Provider to determine the required modifications to the Transmission Provider's Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service.

1.14 Firm Point-To-Point Transmission Service

Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.

1.15 Good Utility Practice

Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(a)(4).

1.16 Interruption

A reduction in non-firm transmission service due to economic reasons pursuant to Section 14.7.

1.17 Load Ratio Share

Ratio of a Transmission Customer's Network Load to the Transmission Provider's total load computed in accordance with Sections 34.2 and 34.3 of the Network Integration Transmission Service under Part III of the Tariff and calculated on a rolling twelve month basis.

1.18 Load Shedding

The systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Part III of the Tariff.

1.19 Long-Term Firm Point-To-Point Transmission Service

Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of one year or more.

1.20 Native Load Customers

The wholesale and retail power customers of the Transmission Provider on whose behalf the Transmission Provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers.

1.21 Network Customer

An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Part III of the Tariff.

1.22 Network Integration Transmission Service

The transmission service provided under Part III of the Tariff.

1.23 Network Load

The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.24 Network Operating Agreement

An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Part III of the Tariff.

1.25 Network Operating Committee

A group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Part III of this Tariff.

1.26 Network Resource

Any designated generating resource owned, purchased or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

1.27 Network Upgrades

Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System.

1.28 Non-Firm Point-To-Point Transmission Service

Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Section 14.7 under Part II of this Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.29 Non-Firm Sale

An energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

1.30 Open Access Same-Time Information System (OASIS)

The information system and standards of conduct contained in Part 37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

1.31 Part I

Tariff Definitions and Common Service Provisions contained in Sections 2 through 12.

1.32 Part II

Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.33 Part III

Tariff Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.34 Parties

The Transmission Provider and the Transmission Customer receiving service under the Tariff.

1.35 Point(s) of Delivery

Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.36 Point(s) of Receipt

Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.37 Point-To-Point Transmission Service

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

1.38 Power Purchaser

The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

1.39 Pre-Confirmed Application

An Application that commits the Transmission Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

1.40 Receiving Party

The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

1.41 Regional Transmission Group (RTG)

A voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate

transmission planning (and expansion), operation and use on a regional (and interregional) basis.

1.42 Reserved Capacity

The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.43 Service Agreement

The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

1.44 Service Commencement Date

The date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Section 15.3 or Section 29.1 under the Tariff.

1.45 Short-Term Firm Point-To-Point Transmission Service

Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of less than one year.

1.46 System Condition

A specified condition on the Transmission Provider's system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority pursuant to Section 13.6. Such conditions must be identified in the Transmission Customer's Service Agreement.

1.47 System Impact Study

An assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a request for either Firm Point-To-Point Transmission Service or Network Integration Transmission Service and (ii) whether any additional costs may be incurred in order to provide transmission service.

1.48 Third-Party Sale

Any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service.

1.49 Transmission Customer

Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission, a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Tariff.

1.50 Transmission Provider

The public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff.

1.51 Transmission Provider's Monthly Transmission System Peak

The maximum firm usage of the Transmission Provider's Transmission System in a calendar month.

1.52 Transmission Service

Point-To-Point Transmission Service provided under Part II of the Tariff on a firm and non-firm basis.

1.53 Transmission System

The facilities owned, controlled or operated by the Transmission Provider that are used to provide transmission service under Part II and Part III of the Tariff.

2 Initial Allocation and Renewal Procedures

2.1 Initial Allocation of Available Transfer Capability

For purposes of determining whether existing capability on the Transmission Provider's Transmission System is adequate to accommodate a request for firm service under this Tariff, all Completed Applications for new firm transmission service received during the initial sixty (60) day period commencing with the effective date of the Tariff will be deemed to have been filed simultaneously. A lottery system conducted by an independent party shall be used to assign priorities for Completed Applications filed simultaneously. All Completed Applications for firm transmission service received after the initial sixty (60) day period shall be assigned a priority pursuant to Section 13.2.

2.2 Reservation Priority For Existing Firm Service Customers

Existing firm service customers (wholesale requirements and transmission-only, with a contract term of five years or more), have the right to continue to take transmission service from the Transmission Provider when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the Transmission Provider or elects to purchase capacity and energy from another supplier. If at the end of the contract term, the Transmission Provider's Transmission System cannot accommodate all of the requests for transmission service, the existing firm service customer must agree to accept a contract term at least equal to the longer of a competing request by any new Eligible Customer or five years and to pay the current just and reasonable rate, as approved by the Commission, for such service. The existing firm service customer must provide notice to the Transmission Provider whether it will exercise its right of first refusal no less than one year prior to the expiration date of its transmission service agreement. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of five years or longer. Service agreements subject to a right of first refusal entered into prior to [the acceptance by the Commission of the Transmission Provider's Attachment K], unless terminated, will become subject to the five year/one year requirement on the first rollover date after [the acceptance by the Commission of the Transmission Provider's Attachment K].

3 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide (or offer to arrange with the local Control Area operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Services (i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation or Other Sources.

The Transmission Provider is required to offer to provide (or offer to arrange with the local Control Area operator as discussed below) the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area (i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve—

Spinning, (iv) Operating Reserve—Supplemental, and (v) Generator Imbalance. The Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply. The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider. A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all of the Ancillary Services identified in this section that were provided by the Transmission Provider associated with the unreserved service. The Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used but did not reserve.

If the Transmission Provider is a public utility providing transmission service but is not a Control Area operator, it may be unable to provide some or all of the Ancillary Services. In this case, the Transmission Provider can fulfill its obligation to provide Ancillary Services by acting as the Transmission Customer's agent to secure these Ancillary Services from the Control Area operator. The Transmission Customer may elect to (i) have the Transmission Provider act as its agent, (ii) secure the Ancillary Services directly from the Control Area operator, or (iii) secure the Ancillary Services (discussed in Schedules 3, 4, 5, 6 and 9) from a third party or by self-supply when technically feasible.

The Transmission Provider shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedules that are attached to and made a part of the Tariff. Three principal requirements apply to discounts for Ancillary Services provided by the Transmission Provider in conjunction with its provision of transmission service as follows: (1) Any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on the Transmission Provider's system. Sections 3.1 through 3.7 below list the seven Ancillary Services.

3.1 Scheduling, System Control and Dispatch Service

The rates and/or methodology are described in Schedule 1.

3.2 Reactive Supply and Voltage Control from Generation or Other Sources Service

The rates and/or methodology are described in Schedule 2.

3.3 Regulation and Frequency Response Service

Where applicable the rates and/or methodology are described in Schedule 3.

3.4 Energy Imbalance Service

Where applicable the rates and/or methodology are described in Schedule 4.

3.5 Operating Reserve—Spinning Reserve Service

Where applicable the rates and/or methodology are described in Schedule 5.

3.6 Operating Reserve—Supplemental Reserve Service

Where applicable the rates and/or methodology are described in Schedule 6.

3.7 Generator Imbalance Service

Where applicable the rates and/or methodology are described in Schedule 9.

4 Open Access Same-Time Information System (OASIS)

Terms and conditions regarding Open Access Same-Time Information System and standards of conduct are set forth in 18 CFR part 37 of the Commission's regulations (Open Access Same-Time Information System and Standards of Conduct for Public Utilities) and 18 CFR part 38 of the Commission's regulations (Business Practice Standards and Communication Protocols for Public Utilities). In the event available transfer capability as posted on the OASIS is insufficient to accommodate a request for firm transmission service, additional studies may be required as provided by this Tariff pursuant to Sections 19 and 32.

The Transmission Provider shall post on its public Web site all rules, standards and practices that (i) relate to the terms and conditions of transmission service, (ii) are not subject to a North American Energy Standards Board (NAESB) copyright restriction, and (iii) are not otherwise included in this Tariff. The Transmission Provider shall post on OASIS an electronic link to these rules, standards and practices, and shall post on its public Web site an electronic link to the NAESB Web site where any rules, standards and practices that are protected by copyright may be obtained. The Transmission Provider shall also make available on its public Web site a statement of the process by which the Transmission Provider shall add, delete or otherwise modify the rules, standards and practices that are posted on its website. Such process shall set forth the means by which the Transmission Provider shall provide reasonable advance notice to Transmission Customers and Eligible Customers of any such additions, deletions or modifications, the associated effective date, and any additional implementation procedures that the Transmission Provider deems appropriate.

5 Local Furnishing Bonds

5.1 Transmission Providers That Own Facilities Financed by Local Furnishing Bonds

This provision is applicable only to Transmission Providers that have financed facilities for the local furnishing of electric energy with tax-exempt bonds, as described in Section 142(f) of the Internal Revenue Code (''local furnishing bonds''). Notwithstanding any other provision of this Tariff, the Transmission Provider shall not be required to provide transmission service to any Eligible Customer pursuant to this Tariff if the provision of such transmission service would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance the Transmission Provider's facilities that would be used in providing such transmission service.

5.2 Alternative Procedures for Requesting Transmission Service

(i) If the Transmission Provider determines that the provision of transmission service requested by an Eligible Customer would jeopardize the tax-exempt status of any local

furnishing bond(s) used to finance its facilities that would be used in providing such transmission service, it shall advise the Eligible Customer within thirty (30) days of receipt of the Completed Application.

(ii) If the Eligible Customer thereafter renews its request for the same transmission service referred to in (i) by tendering an application under Section 211 of the Federal Power Act, the Transmission Provider, within ten (10) days of receiving a copy of the Section 211 application, will waive its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act. The Commission, upon receipt of the Transmission Provider's waiver of its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act, shall issue an order under Section 211 of the Federal Power Act. Upon issuance of the order under Section 211 of the Federal Power Act, the Transmission Provider shall be required to provide the requested transmission service in accordance with the terms and conditions of this Tariff.

6 Reciprocity

A Transmission Customer receiving transmission service under this Tariff agrees to provide comparable transmission service that it is capable of providing to the Transmission Provider on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate affiliates. A Transmission Customer that is a member of, or takes transmission service from, a power pool, Regional Transmission Group, Regional Transmission Organization (RTO), Independent System Operator (ISO) or other transmission organization approved by the Commission for the operation of transmission facilities also agrees to provide comparable transmission service to the members of such power pool and Regional Transmission Group, RTO, ISO or other transmission organization on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate affiliates.

This reciprocity requirement applies not only to the Transmission Customer that obtains transmission service under the Tariff, but also to all parties to a transaction that involves the use of transmission service under the Tariff, including the power seller, buyer and any intermediary, such as a power marketer. This reciprocity requirement also applies to any Eligible Customer that owns, controls or operates transmission facilities that uses an intermediary, such as a power marketer, to request transmission service under the Tariff. If the Transmission Customer does not own, control or operate transmission facilities, it must include in its Application a sworn statement of one of its duly authorized officers or other representatives that the purpose of its Application is not to assist an Eligible Customer to avoid the requirements of this provision.

7 Billing and Payment

7.1 Billing Procedure

Within a reasonable time after the first day of each month, the Transmission Provider shall submit an invoice to the Transmission Customer for the charges for all services furnished under the Tariff during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to the Transmission Provider, or by wire transfer to a bank named by the Transmission Provider.

7.2 Interest on Unpaid Balances

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 CFR 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by the Transmission Provider.

7.3 Customer Default

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to the Transmission Provider on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the Transmission Provider notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, the Transmission Provider may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between the Transmission Provider and the Transmission Customer, the Transmission Provider will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then the Transmission Provider may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

8 Accounting for the Transmission Provider's Use of the Tariff

The Transmission Provider shall record the following amounts, as outlined below.

8.1 Transmission Revenues

Include in a separate operating revenue account or subaccount the revenues it receives from Transmission Service when making Third-Party Sales under Part II of the Tariff.

8.2 Study Costs and Revenues

Include in a separate transmission operating expense account or subaccount, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies which the Transmission Provider conducts to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including making Third-Party Sales under the Tariff; and include in a separate operating revenue account or subaccount the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Transmission Customer's billing under the Tariff.

9 Regulatory Filings

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of the Transmission Provider to unilaterally make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules

and regulations promulgated thereunder.

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

10 Force Majeure and Indemnification

10.1 Force Majeure

An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing.

Neither the Transmission Provider nor the Transmission Customer will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.

10.2 Indemnification

The Transmission Customer shall at all times indemnify, defend, and save the Transmission Provider harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the Transmission Provider's performance of its obligations under this Tariff on behalf of the Transmission Customer, except in cases of negligence or intentional wrongdoing by the Transmission Provider.

11 Creditworthiness

The Transmission Provider will specify its Creditworthiness procedures in Attachment L.

12 Dispute Resolution Procedures

12.1 Internal Dispute Resolution Procedures

Any dispute between a Transmission Customer and the Transmission Provider involving transmission service under the Tariff (excluding applications for rate changes or other changes to the Tariff, or to any Service Agreement entered into under the Tariff, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of the Transmission Provider and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

12.2 External Arbitration Procedures

Any arbitration initiated under the Tariff shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or Regional Transmission Group rules.

12.3 Arbitration Decisions

Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the Tariff and any Service Agreement entered into under the Tariff and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

12.4 Costs

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

1. The cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

2. One half the cost of the single arbitrator jointly chosen by the Parties.

12.5 Rights Under the Federal Power Act

Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

II. Point-To-Point Transmission Service

Preamble

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service pursuant to the applicable terms and conditions of this Tariff. Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transfer of such capacity and energy to designated Point(s) of Delivery.

13 Nature of Firm Point-To-Point Transmission Service

13.1 Term

The minimum term of Firm Point-To-Point Transmission Service shall be one day and the maximum term shall be specified in the Service Agreement.

13.2 Reservation Priority

(i) Long-Term Firm Point-To-Point Transmission Service shall be available on a first-come, first-served basis, *i.e.*, in the chronological sequence in which each Transmission Customer has requested service.

(ii) Reservations for Short-Term Firm Point-To-Point Transmission Service will be conditional based upon the length of the requested transaction. However, Pre-Confirmed Applications for Short-Term Point-to-Point Transmission Service will receive priority over earlier-submitted requests that are not Pre-Confirmed and that have equal or shorter duration. Among

requests with the same duration and pre-confirmation status (Pre-Confirmed or not confirmed), priority will be given to an Eligible Customer's request that offers the highest price, followed by the date and time of the request.

(iii) If the Transmission System becomes oversubscribed, requests for longer term service may preempt requests for shorter term service up to the following deadlines: one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. Before the conditional reservation deadline, if available transfer capability is insufficient to satisfy all Applications, an Eligible Customer with a reservation for shorter term service or equal duration service and lower price has the right of first refusal to match any longer term request or equal duration service with a higher price before losing its reservation priority. A longer term competing request for Short-Term Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 13.8) from being notified by the Transmission Provider of a longer-term competing request for Short-Term Firm Point-To-Point Transmission Service. When a longer duration request preempts multiple shorter duration requests, the shorter duration requests shall have simultaneous opportunities to exercise the right of first refusal. Duration, pre-confirmation status, price and time of response will be used to determine the order by which the multiple shorter duration requests will be able to exercise the right of first refusal. After the conditional reservation deadline, service will commence pursuant to the terms of Part II of the Tariff.

(iv) Firm Point-To-Point Transmission Service will always have a reservation priority over Non-Firm Point-To-Point Transmission Service under the Tariff. All Long-Term Firm Point-To-Point Transmission Service will have equal reservation priority with Native Load Customers and Network Customers. Reservation priorities for existing firm service customers are provided in Section 2.2.

13.3 Use of Firm Transmission Service by the Transmission Provider

The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after [insert date sixty (60) days after publication in **Federal Register**] or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of the Point-To-Point Transmission Service to make Third-Party Sales.

13.4 Service Agreements

The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it submits a Completed Application for Long-Term Firm Point-To-Point Transmission Service. The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it first submits a Completed Application for Short-Term Firm Point-To-Point Transmission Service pursuant to the Tariff. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations. An Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved and that has not executed a Service Agreement will be deemed, for purposes of assessing any appropriate charges and penalties, to have executed the appropriate Service Agreement. The Service Agreement shall, when applicable, specify any conditional curtailment options selected by the Transmission Customer. Where the Service Agreement contains conditional curtailment options and is subject to a biennial reassessment as described in Section 15.4, the Transmission Provider shall provide the Transmission Customer notice of any changes to the curtailment conditions no less than 90 days prior to the date for imposition of new curtailment conditions. Concurrent with such notice, the Transmission Provider shall provide the Transmission Customer with the reassessment study and a narrative description of the study, including the reasons for changes to the number of hours per year or System Conditions under which conditional curtailment may occur.

13.5 Transmission Customer Obligations for Facility Additions or Redispatch Costs

In cases where the Transmission Provider determines that the Transmission System is not capable of providing Firm Point-To-Point Transmission Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Point-To-Point Transmission Service, or (2) interfering with the Transmission Provider's ability to meet prior firm contractual commitments to others, the Transmission Provider will be obligated to expand or upgrade its Transmission System pursuant to the terms of Section 15.4. The Transmission Customer must agree to compensate the Transmission Provider for any necessary transmission facility additions pursuant to the terms of Section 27. To the extent the Transmission Provider can relieve any system constraint by redispatching the Transmission Provider's resources, it shall do so, provided that the Eligible Customer agrees to compensate the Transmission Provider pursuant to the terms of Section 27 and agrees to either (i) compensate the Transmission Provider for any necessary transmission facility additions or (ii) accept the service subject to a biennial reassessment by the Transmission Provider of redispatch requirements as described in Section 15.4. Any redispatch, Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer on an incremental basis under the Tariff will be specified in the Service Agreement prior to initiating service.

13.6 Curtailment of Firm Transmission Service

In the event that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such system and the system directly and indirectly interconnected with Transmission Provider's Transmission System, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. Transmission Provider may elect to implement such Curtailments pursuant to the Transmission Loading Relief procedures specified in Attachment J. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the Transmission Provider will curtail service to Network Customers and Transmission Customers taking Firm Point-To-Point Transmission Service on a basis comparable to the curtailment of service to the Transmission Provider's Native Load Customers. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission

Service. Long-Term Firm Point-to-Point Service subject to conditions described in Section 15.4 shall be curtailed with secondary service in cases where the conditions apply, but otherwise will be curtailed on a pro rata basis with other Firm Transmission Service. When the Transmission Provider determines that an electrical emergency exists on its Transmission System and implements emergency procedures to Curtail Firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission Service provided under the Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. The Transmission Provider will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments.

13.7 Classification of Firm Transmission Service

(a) The Transmission Customer taking Firm Point-To-Point Transmission Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 22.1 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 22.2.

(b) The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are on the Transmission Provider's Transmission System. For such a purchase of transmission service, the resources will be designated as multiple Points of Receipt, unless the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt.

(c) The Transmission Provider shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Receipt. Points of Receipt and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. Each Point of Delivery at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Delivery. Points of Delivery and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 7. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Section 22. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved.

13.8 Scheduling of Firm Point-To-Point Transmission Service

Schedules for the Transmission Customer's Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 10 a.m. [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 10 a.m. will be accommodated, if practicable. Hour-to-hour schedules of any capacity and energy that is to be delivered must be stated in increments of 1,000 kW per hour [or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider]. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their service requests at a common point of receipt into units of 1,000 kW per hour for scheduling and billing purposes. Scheduling changes will be permitted up to twenty (20) minutes [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14 Nature of Non-Firm Point-To-Point Transmission Service

14.1 Term

Non-Firm Point-To-Point Transmission Service will be available for periods ranging from one (1) hour to one (1) month. However, a Purchaser of Non-Firm Point-To-Point Transmission Service will be entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies is greater than one month, subject to the requirements of Section 18.3.

14.2 Reservation Priority

Non-Firm Point-To-Point Transmission Service shall be available from transfer capability in excess of that needed for reliable service to Native Load Customers, Network Customers and other Transmission Customers taking Long-Term and Short-Term Firm Point-To-Point Transmission Service. A higher priority will be assigned first to reservations with a longer duration of service and second to Pre-Confirmed Applications. In the event the Transmission System is constrained, competing requests of the same Pre-Confirmation status and equal duration will be prioritized based on the highest price offered by the Eligible Customer for the Transmission Service. Eligible Customers that have already reserved shorter term service have the right of first refusal to match any longer term reservation before being preempted. A longer term competing request for Non-Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request: (a) Immediately for hourly Non-Firm Point-To-Point Transmission Service after notification by the Transmission Provider; and, (b) within 24 hours (or earlier if necessary to

comply with the scheduling deadlines provided in section 14.6) for Non-Firm Point-To-Point Transmission Service other than hourly transactions after notification by the Transmission Provider. Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have the lowest reservation priority under the Tariff.

14.3 Use of Non-Firm Point-To-Point Transmission Service by the Transmission Provider

The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after May 14, 2007 or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of Non-Firm Point-To-Point Transmission Service to make Third-Party Sales.

14.4 Service Agreements

The Transmission Provider shall offer a standard form Non-Firm Point-To-Point Transmission Service Agreement (Attachment B) to an Eligible Customer when it first submits a Completed Application for Non-Firm Point-To-Point Transmission Service pursuant to the Tariff. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

14.5 Classification of Non-Firm Point-To-Point Transmission Service

Non-Firm Point-To-Point Transmission Service shall be offered under terms and conditions contained in Part II of the Tariff. The Transmission Provider undertakes no obligation under the Tariff to plan its Transmission System in order to have sufficient capacity for Non-Firm Point-To-Point Transmission Service. Parties requesting Non-Firm Point-To-Point Transmission Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its non-firm capacity reservation. Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedule 8.

14.6 Scheduling of Non-Firm Point-To-Point Transmission Service

Schedules for Non-Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 2 p.m. [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 2 p.m. will be accommodated, if practicable. Hour-to-hour schedules of energy that is to be delivered must be stated in increments of 1,000 kW per hour [or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider]. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their schedules at a common Point of Receipt into units of 1,000 kW per hour. Scheduling changes will be permitted up to twenty (20) minutes [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14.7 Curtailment or Interruption of Service

The Transmission Provider reserves the right to Curtail, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for reliability reasons when an emergency or other unforeseen condition threatens to impair or degrade the reliability of its Transmission System or the systems directly and indirectly interconnected with Transmission Provider's Transmission System. Transmission Provider may elect to implement such Curtailments pursuant to the Transmission Loading Relief procedures specified in Attachment J. The Transmission Provider reserves the right to Interrupt, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for economic reasons in order to accommodate (1) a request for Firm Transmission Service, (2) a request for Non-Firm Point-To-Point Transmission Service of greater duration, (3) a request for Non-Firm Point-To-Point Transmission Service of equal duration with a higher price, (4) transmission service for Network Customers from non-designated resources, or (5) transmission service for Firm Point-to-Point Transmission Service during conditional curtailment periods as described in Section 15.4. The Transmission Provider also will discontinue or reduce service to the Transmission Customer to the extent that deliveries for transmission are discontinued or reduced at the Point(s) of Receipt. Where required, Curtailments or Interruptions will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. If multiple transactions require Curtailment or Interruption, to the extent practicable and consistent with Good Utility Practice, Curtailments or Interruptions will be made to transactions of the shortest term (*e.g.*, hourly non-firm transactions will be Curtailed or Interrupted before daily non-firm transactions and daily non-firm transactions will be Curtailed or Interrupted before weekly non-firm transactions). Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have a lower priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. The Transmission Provider will provide advance notice of Curtailment or Interruption where such

notice can be provided consistent with Good Utility Practice.

15 Service Availability

15.1 General Conditions

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service over, on or across its Transmission System to any Transmission Customer that has met the requirements of Section 16.

15.2 Determination of Available Transfer Capability

A description of the Transmission Provider's specific methodology for assessing available transfer capability posted on the Transmission Provider's OASIS (Section 4) is contained in Attachment C of the Tariff. In the event sufficient transfer capability may not exist to accommodate a service request, the Transmission Provider will respond by performing a System Impact Study.

15.3 Initiating Service in the Absence of an Executed Service Agreement

If the Transmission Provider and the Transmission Customer requesting Firm or Non-Firm Point-To-Point Transmission Service cannot agree on all the terms and conditions of the Point-To-Point Service Agreement, the Transmission Provider shall file with the Commission, within thirty (30) days after the date the Transmission Customer provides written notification directing the Transmission Provider to file, an unexecuted Point-To-Point Service Agreement containing terms and conditions deemed appropriate by the Transmission Provider for such requested Transmission Service. The Transmission Provider shall commence providing Transmission Service subject to the Transmission Customer agreeing to (i) compensate the Transmission Provider at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of the Tariff including posting appropriate security deposits in accordance with the terms of Section 17.3.

15.4 Obligation To Provide Transmission Service That Requires Expansion or Modification of the Transmission System, Redispatch or Conditional Curtailment

(a) If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service, consistent with its planning obligations in Attachment K, provided the Transmission Customer agrees to compensate the Transmission Provider for such costs pursuant to the terms of Section 27. The Transmission Provider will conform to Good Utility Practice and its planning obligations in Attachment K, in determining the need for new facilities and in the design and construction of such facilities. The obligation applies only to those facilities that the Transmission Provider has the right to expand or modify.

(b) If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to provide redispatch from its own resources until (i) Network Upgrades are completed for the Transmission Customer, (ii) the Transmission Provider determines through a biennial reassessment that it can no longer reliably provide the redispatch, or (iii) the Transmission Customer terminates the service because of redispatch changes resulting from the reassessment. A Transmission Provider shall not unreasonably deny self-provided redispatch or redispatch arranged by the Transmission Customer from a third party resource.

(c) If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will offer the Firm Transmission Service with the condition that the Transmission Provider may curtail the service prior to the curtailment of other Firm Transmission Service for a specified number of hours per year or during System Condition(s). If the Transmission Customer accepts the service, the Transmission Provider will use due diligence to provide the service until (i) Network Upgrades are completed for the Transmission Customer, (ii) the Transmission Provider determines through a biennial reassessment that it can no longer reliably provide such service, or (iii) the Transmission Customer terminates the service because the reassessment increased the number of hours per year of conditional curtailment or changed the System Conditions.

15.5 Deferral of Service

The Transmission Provider may defer providing service until it completes construction of new transmission facilities or upgrades needed to provide Firm Point-To-Point Transmission Service whenever the Transmission Provider determines that providing the requested service would, without such new facilities or upgrades, impair or degrade reliability to any existing firm services.

15.6 Other Transmission Service Schedules

Eligible Customers receiving transmission service under other agreements on file with the Commission may continue to receive transmission service under those agreements until such time as those agreements may be modified by the Commission.

15.7 Real Power Losses

Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factors are as follows: [To be completed by the Transmission Provider].

16 Transmission Customer Responsibilities

16.1 Conditions Required of Transmission Customers

Point-To-Point Transmission Service shall be provided by the Transmission Provider only if the following conditions are satisfied by the Transmission Customer:

(a) The Transmission Customer has pending a Completed Application for service;

(b) The Transmission Customer meets the creditworthiness criteria set forth in Section 11;

(c) The Transmission Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the Transmission Provider prior to the time service under Part II of the Tariff commences;

(d) The Transmission Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer under Part II of the Tariff, whether or not the Transmission Customer takes service for the full term of its reservation;

(e) The Transmission Customer provides the information required by the Transmission Provider's planning process established in Attachment K; and

(f) The Transmission Customer has executed a Point-To-Point Service

Agreement or has agreed to receive service pursuant to Section 15.3.

16.2 Transmission Customer Responsibility for Third-Party Arrangements

Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Transmission Customer requesting service. The Transmission Customer shall provide, unless waived by the Transmission Provider, notification to the Transmission Provider identifying such systems and authorizing them to schedule the capacity and energy to be transmitted by the Transmission Provider pursuant to Part II of the Tariff on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. However, the Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

17 Procedures for Arranging Firm Point-To-Point Transmission Service

17.1 Application

A request for Firm Point-To-Point Transmission Service for periods of one year or longer must contain a written Application to: [Transmission Provider Name and Address], at least sixty (60) days in advance of the calendar month in which service is to commence. The Transmission Provider will consider requests for such firm service on shorter notice when feasible. Requests for firm service for periods of less than one year shall be subject to expedited procedures that shall be negotiated between the Parties within the time constraints provided in Section 17.5. All Firm Point-To-Point Transmission Service requests should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the priority of the Application.

17.2 Completed Application

A Completed Application shall provide all of the information included in 18 CFR 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The location of the Point(s) of Receipt and Point(s) of Delivery and the identities of the Delivering Parties and the Receiving Parties;

(iv) The location of the generating facility(ies) supplying the capacity and energy and the location of the load ultimately served by the capacity and energy transmitted. The Transmission Provider will treat this information as confidential except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations;

(v) A description of the supply characteristics of the capacity and energy to be delivered;

(vi) An estimate of the capacity and energy expected to be delivered to the Receiving Party;

(vii) The Service Commencement Date and the term of the requested Transmission Service;

(viii) The transmission capacity requested for each Point of Receipt and each Point of Delivery on the Transmission Provider's Transmission System; customers may combine their requests for service in order to satisfy the minimum transmission capacity requirement;

(ix) A statement indicating whether the Transmission Customer commits to a Pre-Confirmed Request, *i.e.*, will execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service; and

(x) Any additional information required by the Transmission Provider's planning process established in Attachment K.

The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

17.3 Deposit

A Completed Application for Firm Point-To-Point Transmission Service also shall include a deposit of either one month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month. If the Application is rejected by the Transmission Provider because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a Request For Proposals (RFP), said deposit shall be returned with interest less any reasonable costs incurred by the Transmission Provider in connection with the review of the losing bidder's Application. The deposit also will be returned with interest less any reasonable costs incurred by the Transmission Provider if the Transmission Provider is unable to complete new facilities needed to provide the service. If an Application is withdrawn or the Eligible Customer decides not to enter into a Service Agreement for Firm Point-To-Point Transmission Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by the Transmission Provider to the extent such costs have not already been recovered by the Transmission Provider from the Eligible Customer. The Transmission Provider will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities are subject to the provisions of Section 19. If a Service Agreement for Firm Point-To-Point Transmission Service is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration or termination of the Service Agreement for Firm Point-To-Point Transmission Service. Applicable interest shall be computed in accordance with the Commission's regulations at 18 CFR 35.19a(a)(2)(iii), and shall be calculated from the day the deposit check is credited to the Transmission Provider's account.

17.4 Notice of Deficient Application

If an Application fails to meet the requirements of the Tariff, the Transmission Provider shall notify the entity requesting service within fifteen (15) days of receipt of the reasons for such failure. The Transmission Provider will attempt to remedy minor deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application, along with any deposit, with interest. Upon receipt of a new or revised Application that fully complies with the requirements of Part II of the Tariff, the Eligible

Customer shall be assigned a new priority consistent with the date of the new or revised Application.

17.5 Response to a Completed Application

Following receipt of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider shall make a determination of available transfer capability as required in Section 15.2. The Transmission Provider shall notify the Eligible Customer as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application either (i) if it will be able to provide service without performing a System Impact Study or (ii) if such a study is needed to evaluate the impact of the Application pursuant to Section 19.1. Responses by the Transmission Provider must be made as soon as practicable to all completed applications (including applications by its own merchant function) and the timing of such responses must be made on a non-discriminatory basis.

17.6 Execution of Service Agreement

Whenever the Transmission Provider determines that a System Impact Study is not required and that the service can be provided, it shall notify the Eligible Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application. Where a System Impact Study is required, the provisions of Section 19 will govern the execution of a Service Agreement. Failure of an Eligible Customer to execute and return the Service Agreement or request the filing of an unexecuted service agreement pursuant to Section 15.3, within fifteen (15) days after it is tendered by the Transmission Provider will be deemed a withdrawal and termination of the Application and any deposit submitted shall be refunded with interest. Nothing herein limits the right of an Eligible Customer to file another Application after such withdrawal and termination.

17.7 Extensions for Commencement of Service

The Transmission Customer can obtain up to five (5) one-year extensions for the commencement of service. The Transmission Customer may postpone service by paying a non-refundable annual reservation fee equal to one-month's charge for Firm Transmission Service for each year or fraction thereof. If the Eligible Customer does not pay this non-refundable reservation fee within 15 days of notifying the Transmission Provider it intends to extend the commencement of service, then the Eligible Customer's application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest. If during any extension for the commencement of service an Eligible Customer submits a Completed Application for Firm Transmission Service, and such request can be satisfied only by releasing all or part of the Transmission Customer's Reserved Capacity, the original Reserved Capacity will be released unless the following condition is satisfied. Within thirty (30) days, the original Transmission Customer agrees to pay the Firm Point-To-Point transmission rate for its Reserved Capacity concurrent with the new Service Commencement Date. In the event the Transmission Customer elects to release the Reserved Capacity, the reservation fees or portions thereof previously paid will be forfeited.

18 Procedures for Arranging Non-Firm Point-To-Point Transmission Service

18.1 Application

Eligible Customers seeking Non-Firm Point-To-Point Transmission Service must submit a Completed Application to the Transmission Provider. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the service priority of the Application.

18.2 Completed Application

A Completed Application shall provide all of the information included in 18 CFR 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The Point(s) of Receipt and the Point(s) of Delivery;

(iv) The maximum amount of capacity requested at each Point of Receipt and Point of Delivery; and

(v) The proposed dates and hours for initiating and terminating transmission service hereunder.

In addition to the information specified above, when required to properly evaluate system conditions, the Transmission Provider also may ask the Transmission Customer to provide the following:

(vi) The electrical location of the initial source of the power to be transmitted pursuant to the Transmission Customer's request for service; and

(vii) The electrical location of the ultimate load.

The Transmission Provider will treat this information in (vi) and (vii) as confidential at the request of the Transmission Customer except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice, or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

(viii) A statement indicating whether the Transmission Customer commits to a Pre-Confirmed Request, *i.e.*, will execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

18.3 Reservation of Non-Firm Point-to-Point Transmission Service

Requests for monthly service shall be submitted no earlier than sixty (60) days before service is to commence; requests for weekly service shall be submitted no earlier than fourteen (14) days before service is to commence, requests for daily service shall be submitted no earlier than two (2) days before service is to commence, and requests for hourly service shall be submitted no earlier than noon the day before service is to commence. Requests for service received later than 2 p.m. prior to the day service is scheduled to commence will be accommodated if practicable [or such reasonable times that are generally accepted in the region and are consistently adhered to by the Transmission Provider].

18.4 Determination of Available Transfer Capability

Following receipt of a tendered schedule the Transmission Provider will make a determination on a non-discriminatory basis of available transfer capability pursuant to Section 15.2. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service (i) thirty (30) minutes for hourly service, (ii) thirty (30) minutes for daily

service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service. [Or such reasonable times that are generally accepted in the region and are consistently adhered to by the Transmission Provider].

19 Additional Study Procedures for Firm Point-to-Point Transmission Service Requests

19.1 Notice of Need for System Impact Study

After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. Once informed, the Eligible Customer shall timely notify the Transmission Provider if it elects not to have the Transmission Provider study redispatch or conditional curtailment as part of the System Impact Study. If notification is provided prior to tender of the System Impact Study Agreement, the Eligible Customer can avoid the costs associated with the study of these options. The Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest.

19.2 System Impact Study Agreement and Cost Reimbursement

(i) The System Impact Study Agreement will clearly specify the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the requests for service, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 20.

19.3 System Impact Study Procedures

Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify (1) any system constraints, identified with specificity by transmission element or flowgate, (2) redispatch options (when requested by a Transmission Customer) including an estimate of the cost of redispatch, (3) conditional curtailment options (when requested by a Transmission Customer) including the number of hours per year and the System Conditions during which conditional curtailment may occur, and (4) additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. For customers requesting the study of redispatch options, the System Impact Study shall (1) identify all resources located within the Transmission Provider's Control Area that can significantly contribute toward relieving the system constraint and (2) provide a measurement of each resource's impact on the system constraint. If the Transmission Provider possesses information indicating that any resource outside its Control Area could relieve the constraint, it shall identify each such resource in the System Impact Study. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement pursuant to Section 15.3, or the Application shall be deemed terminated and withdrawn.

19.4 Facilities Study Procedures

If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Transmission Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Transmission Customer, (ii) the Transmission Customer's appropriate share of the cost of any required

Network Upgrades as determined pursuant to the provisions of Part II of the Tariff, and (iii) the time required to complete such construction and initiate the requested service. The Transmission Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Transmission Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request will no longer be a Completed Application and shall be deemed terminated and withdrawn.

19.5 Facilities Study Modifications

Any change in design arising from inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the Transmission Provider that significantly affect the final cost of new facilities or upgrades to be charged to the Transmission Customer pursuant to the provisions of Part II of the Tariff.

19.6 Due Diligence in Completing New Facilities

The Transmission Provider shall use due diligence to add necessary facilities or upgrade its Transmission System within a reasonable time. The Transmission Provider will not upgrade its existing or planned Transmission System in order to provide the requested Firm Point-To-Point Transmission Service if doing so would impair system reliability or otherwise impair or degrade existing firm service.

19.7 Partial Interim Service

If the Transmission Provider determines that it will not have adequate transfer capability to satisfy the full amount of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider nonetheless shall be obligated to offer and provide the portion of the requested Firm Point-To-Point Transmission Service that can be accommodated without addition of any facilities and through redispatch. However, the Transmission Provider shall not be obligated to provide the incremental amount of requested Firm Point-To-Point Transmission Service that requires the addition of facilities or upgrades to the Transmission System until such facilities or upgrades have been placed in service.

19.8 Expedited Procedures for New Facilities

In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the Transmission Provider to tender at one time, together with the results of required studies, an ''Expedited Service Agreement'' pursuant to which the Eligible Customer would agree to compensate the Transmission Provider for all costs incurred pursuant to the terms of the Tariff. In order to exercise this option, the Eligible Customer shall request in writing an expedited Service Agreement covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While the Transmission Provider agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer must agree in writing to compensate the Transmission Provider for all costs incurred pursuant to the provisions of the Tariff. The Eligible Customer shall execute and return such an Expedited Service Agreement within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

19.9 Penalties for Failure To Meet Study Deadlines

Sections 19.3 and 19.4 require a Transmission Provider to use due diligence to meet 60-day study completion deadlines for System Impact Studies and Facilities Studies.

(i) The Transmission Provider is required to file a notice with the Commission in the event that more than twenty (20) percent of non-Affiliates' System Impact Studies and Facilities Studies completed by the Transmission Provider in any two consecutive calendar quarters are not completed within the 60-day study completion deadlines. Such notice must be filed within thirty (30) days of the end of the calendar quarter triggering the notice requirement.

(ii) For the purposes of calculating the percent of non-Affiliates' System Impact Studies and Facilities Studies processed outside of the 60-day study completion deadlines, the Transmission Provider shall consider all System Impact Studies and Facilities Studies that it completes for non-Affiliates during the calendar quarter. The percentage should be calculated by dividing the number of those studies which are completed on time by the total number of completed studies. The Transmission Provider may provide an explanation in its notification filing to the Commission if it believes there are extenuating circumstances that prevented it from meeting the 60-day study completion deadlines.

(iii) The Transmission Provider is subject to an operational penalty if it completes ten (10) percent or more of non-Affiliates' System Impact Studies and Facilities Studies outside of the 60-day study completion deadlines for each of the two calendar quarters immediately following the quarter that triggered its notification filing to the Commission. The operational penalty will be assessed for each calendar quarter for which an operational penalty applies, starting with the calendar quarter immediately following the quarter that triggered the Transmission Provider's notification filing to the Commission. The operational penalty will continue to be assessed each quarter until the Transmission Provider completes at least ninety (90) percent of all non-Affiliates' System Impact Studies and Facilities Studies within the 60-day deadline.

(iv) For penalties assessed in accordance with subsection (iii) above, the penalty amount for each System Impact Study or Facilities Study shall be equal to $500 for each day the Transmission Provider takes to complete that study beyond the 60-day deadline.

20 Procedures if the Transmission Provider Is Unable To Complete New Transmission Facilities for Firm Point-to-Point Transmission Service

20.1 Delays in Construction of New Facilities

If any event occurs that will materially affect the time for completion of new facilities, or the ability to complete them, the Transmission Provider shall promptly notify the Transmission Customer. In such circumstances, the Transmission Provider shall within thirty (30) days of notifying the Transmission Customer of such delays, convene a technical meeting with the Transmission Customer to evaluate the alternatives available to the Transmission Customer. The Transmission Provider also shall make available to the Transmission

Customer studies and work papers related to the delay, including all information that is in the possession of the Transmission Provider that is reasonably needed by the Transmission Customer to evaluate any alternatives.

20.2 Alternatives to the Original Facility Additions

When the review process of Section 20.1 determines that one or more alternatives exist to the originally planned construction project, the Transmission Provider shall present such alternatives for consideration by the Transmission Customer. If, upon review of any alternatives, the Transmission Customer desires to maintain its Completed Application subject to construction of the alternative facilities, it may request the Transmission Provider to submit a revised Service Agreement for Firm Point-To-Point Transmission Service. If the alternative approach solely involves Non-Firm Point-To-Point Transmission Service, the Transmission Provider shall promptly tender a Service Agreement for Non-Firm Point-To-Point Transmission Service providing for the service. In the event the Transmission Provider concludes that no reasonable alternative exists and the Transmission Customer disagrees, the Transmission Customer may seek relief under the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

20.3 Refund Obligation for Unfinished Facility Additions

If the Transmission Provider and the Transmission Customer mutually agree that no other reasonable alternatives exist and the requested service cannot be provided out of existing capability under the conditions of Part II of the Tariff, the obligation to provide the requested Firm Point-To-Point Transmission Service shall terminate and any deposit made by the Transmission Customer shall be returned with interest pursuant to Commission regulations 35.19a(a)(2)(iii). However, the Transmission Customer shall be responsible for all prudently incurred costs by the Transmission Provider through the time construction was suspended.

21 Provisions Relating to Transmission Construction and Services on the Systems of Other Utilities

21.1 Responsibility for Third-Party System Additions

The Transmission Provider shall not be responsible for making arrangements for any necessary engineering, permitting, and construction of transmission or distribution facilities on the system(s) of any other entity or for obtaining any regulatory approval for such facilities. The Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

21.2 Coordination of Third-Party System Additions

In circumstances where the need for transmission facilities or upgrades is identified pursuant to the provisions of Part II of the Tariff, and if such upgrades further require the addition of transmission facilities on other systems, the Transmission Provider shall have the right to coordinate construction on its own system with the construction required by others. The Transmission Provider, after consultation with the Transmission Customer and representatives of such other systems, may defer construction of its new transmission facilities, if the new transmission facilities on another system cannot be completed in a timely manner. The Transmission Provider shall notify the Transmission Customer in writing of the basis for any decision to defer construction and the specific problems which must be resolved before it will initiate or resume construction of new facilities. Within sixty (60) days of receiving written notification by the Transmission Provider of its intent to defer construction pursuant to this section, the Transmission Customer may challenge the decision in accordance with the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

22 Changes in Service Specifications

22.1 Modifications On a Non-Firm Basis

The Transmission Customer taking Firm Point-To-Point Transmission Service may request the Transmission Provider to provide transmission service on a non-firm basis over Receipt and Delivery Points other than those specified in the Service Agreement (''Secondary Receipt and Delivery Points''), in amounts not to exceed its firm capacity reservation, without incurring an additional Non-Firm Point-To-Point Transmission Service charge or executing a new Service Agreement, subject to the following conditions.

(a) Service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis and will not displace any firm or non-firm service reserved or scheduled by third-parties under the Tariff or by the Transmission Provider on behalf of its Native Load Customers.

(b) The sum of all Firm and non-firm Point-To-Point Transmission Service provided to the Transmission Customer at any time pursuant to this section shall not exceed the Reserved Capacity in the relevant Service Agreement under which such services are provided.

(c) The Transmission Customer shall retain its right to schedule Firm Point-To-Point Transmission Service at the Receipt and Delivery Points specified in the relevant Service Agreement in the amount of its original capacity reservation.

(d) Service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the filing of an Application for Non-Firm Point-To-Point Transmission Service under the Tariff. However, all other requirements of Part II of the Tariff (except as to transmission rates) shall apply to transmission service on a non-firm basis over Secondary Receipt and Delivery Points.

22.2 Modification On a Firm Basis

Any request by a Transmission Customer to modify Receipt and Delivery Points on a firm basis shall be treated as a new request for service in accordance with Section 17 hereof, except that such Transmission Customer shall not be obligated to pay any additional deposit if the capacity reservation does not exceed the amount reserved in the existing Service Agreement. While such new request is pending, the Transmission Customer shall retain its priority for service at the existing firm Receipt and Delivery Points specified in its Service Agreement.

23 Sale or Assignment of Transmission Service

23.1 Procedures for Assignment or Transfer of Service

Subject to Commission approval of any necessary filings, a Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Service Agreement, but only to another Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Service Agreement is hereafter referred to as the Reseller. Compensation to Resellers shall be at rates established by agreement with the Assignee. The

Assignee must execute a service agreement with the Transmission Provider prior to the date on which the reassigned service commences that will govern the provision of reassigned service. The Transmission Provider shall credit or charge the Reseller, as appropriate, for any differences between the price reflected in the Assignee's Service Agreement and the Reseller's Service Agreement with the Transmission Provider. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Service Agreement, the Assignee will receive the same services as did the Reseller and the priority of service for the Assignee will be the same as that of the Reseller. The Assignee will be subject to all terms and conditions of this Tariff. If the Assignee requests a change in service, the reservation priority of service will be determined by the Transmission Provider pursuant to Section 13.2.

23.2 Limitations on Assignment or Transfer of Service

If the Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Service Agreement, the Transmission Provider will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of the Transmission Provider's generation, transmission, or distribution systems. The Assignee shall compensate the Transmission Provider for performing any System Impact Study needed to evaluate the capability of the Transmission System to accommodate the proposed change and any additional costs resulting from such change. The Reseller shall remain liable for the performance of all obligations under the Service Agreement, except as specifically agreed to by the Transmission Provider and the Reseller through an amendment to the Service Agreement.

23.3 Information on Assignment or Transfer of Service

In accordance with Section 4, all sales or assignments of capacity must be conducted through or otherwise posted on the Transmission Provider's OASIS on or before the date the reassigned service commences and are subject to Section 23.1. Resellers may also use the Transmission Provider's OASIS to post transmission capacity available for resale.

24 Metering and Power Factor Correction at Receipt and Delivery Points(s)

24.1 Transmission Customer Obligations

Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under Part II of the Tariff and to communicate the information to the Transmission Provider. Such equipment shall remain the property of the Transmission Customer.

24.2 Transmission Provider Access to Metering Data

The Transmission Provider shall have access to metering data, which may reasonably be required to facilitate measurements and billing under the Service Agreement.

24.3 Power Factor

Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as the Transmission Provider pursuant to Good Utility Practices. The power factor requirements are specified in the Service Agreement where applicable.

25 Compensation for Transmission Service

Rates for Firm and Non-Firm Point-To-Point Transmission Service are provided in the Schedules appended to the Tariff: Firm Point-To-Point Transmission Service (Schedule 7); and Non-Firm Point-To-Point Transmission Service (Schedule 8). The Transmission Provider shall use Part II of the Tariff to make its Third-Party Sales. The Transmission Provider shall account for such use at the applicable Tariff rates, pursuant to Section 8.

26 Stranded Cost Recovery

The Transmission Provider may seek to recover stranded costs from the Transmission Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, the Transmission Provider must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

27 Compensation for New Facilities and Redispatch Costs

Whenever a System Impact Study performed by the Transmission Provider in connection with the provision of Firm Point-To-Point Transmission Service identifies the need for new facilities, the Transmission Customer shall be responsible for such costs to the extent consistent with Commission policy. Whenever a System Impact Study performed by the Transmission Provider identifies capacity constraints that may be relieved by redispatching the Transmission Provider's resources to eliminate such constraints, the Transmission Customer shall be responsible for the redispatch costs to the extent consistent with Commission policy.

III. Network Integration Transmission Service

Preamble

The Transmission Provider will provide Network Integration Transmission Service pursuant to the applicable terms and conditions contained in the Tariff and Service Agreement. Network Integration Transmission Service allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which the Transmission Provider utilizes its Transmission System to serve its Native Load Customers. Network Integration Transmission Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Part II of the Tariff.

28 Nature of Network Integration Transmission Service

28.1 Scope of Service

Network Integration Transmission Service is a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their Network Load located in the Transmission Provider's Control Area and any additional load that may be designated pursuant to Section 31.3 of the Tariff. The Network Customer taking Network Integration Transmission Service must obtain or provide Ancillary Services pursuant to Section 3.

28.2 Transmission Provider Responsibilities

The Transmission Provider will plan, construct, operate and maintain its

Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System. The Transmission Provider, on behalf of its Native Load Customers, shall be required to designate resources and loads in the same manner as any Network Customer under Part III of this Tariff. This information must be consistent with the information used by the Transmission Provider to calculate available transfer capability. The Transmission Provider shall include the Network Customer's Network Load in its Transmission System planning and shall, consistent with Good Utility Practice and Attachment K, endeavor to construct and place into service sufficient transfer capability to deliver the Network Customer's Network Resources to serve its Network Load on a basis comparable to the Transmission Provider's delivery of its own generating and purchased resources to its Native Load Customers.

28.3 Network Integration Transmission Service

The Transmission Provider will provide firm transmission service over its Transmission System to the Network Customer for the delivery of capacity and energy from its designated Network Resources to service its Network Loads on a basis that is comparable to the Transmission Provider's use of the Transmission System to reliably serve its Native Load Customers.

28.4 Secondary Service

The Network Customer may use the Transmission Provider's Transmission System to deliver energy to its Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Secondary service shall not require the filing of an Application for Network Integration Transmission Service under the Tariff. However, all other requirements of Part III of the Tariff (except for transmission rates) shall apply to secondary service. Deliveries from resources other than Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under Part II of the Tariff.

28.5 Real Power Losses

Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factors are as follows: [To be completed by the Transmission Provider].

28.6 Restrictions on Use of Service

The Network Customer shall not use Network Integration Transmission Service for (i) sales of capacity and energy to non-designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Network Integration Transmission Service shall use Point-To-Point Transmission Service under Part II of the Tariff for any Third-Party Sale which requires use of the Transmission Provider's Transmission System. The Transmission Provider shall specify any appropriate charges and penalties and all related terms and conditions applicable in the event that a Network Customer uses Network Integration Transmission Service or secondary service pursuant to Section 28.4 to facilitate a wholesale sale that does not serve a Network Load.

29 Initiating Service

29.1 Condition Precedent for Receiving Service

Subject to the terms and conditions of Part III of the Tariff, the Transmission Provider will provide Network Integration Transmission Service to any Eligible Customer, provided that (i) the Eligible Customer completes an Application for service as provided under Part III of the Tariff, (ii) the Eligible Customer and the Transmission Provider complete the technical arrangements set forth in Sections 29.3 and 29.4, (iii) the Eligible Customer executes a Service Agreement pursuant to Attachment F for service under Part III of the Tariff or requests in writing that the Transmission Provider file a proposed unexecuted Service Agreement with the Commission, and (iv) the Eligible Customer executes a Network Operating Agreement with the Transmission Provider pursuant to Attachment G, or requests in writing that the Transmission Provider file a proposed unexecuted Network Operating Agreement.

29.2 Application Procedures

An Eligible Customer requesting service under Part III of the Tariff must submit an Application, with a deposit approximating the charge for one month of service, to the Transmission Provider as far as possible in advance of the month in which service is to commence. Unless subject to the procedures in Section 2, Completed Applications for Network Integration Transmission Service will be assigned a priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the service priority of the Application. A Completed Application shall provide all of the information included in 18 CFR 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each Transmission Provider substation at the same transmission voltage level. The description should include a ten (10) year forecast of summer and winter load and resource requirements beginning with the first year after the service is scheduled to commence;

(iv) The amount and location of any interruptible loads included in the Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the 10 year load forecast provided in response to (iii) above;

(v) A description of Network Resources (current and 10-year projection). For each on-system Network Resource, such description shall include:

- Unit size and amount of capacity from that unit to be designated as Network Resource
- VAR capability (both leading and lagging) of all generators
- Operating restrictions

—Any periods of restricted operations throughout the year
—Maintenance schedules
—Minimum loading level of unit
—Normal operating level of unit
—Any must-run unit designations required for system reliability or contract reasons

- Approximate variable generating cost ($/MWH) for redispatch computations
- Arrangements governing sale and delivery of power to third parties from generating facilities located in the Transmission Provider Control Area, where only a portion of unit output is designated as a Network Resource;

For each off-system Network Resource, such description shall include:

- Identification of the Network Resource as an off-system resource
- Amount of power to which the customer has rights
- Identification of the control area(s) from which the power will originate
- Delivery point(s) to the Transmission Provider's Transmission System
- Transmission arrangements on the external transmission system(s)
- Operating restrictions, if any

—Any periods of restricted operations throughout the year
—Maintenance schedules
—Minimum loading level of unit
—Normal operating level of unit
—Any must-run unit designations required for system reliability or contract reasons

- Approximate variable generating cost ($/MWH) for redispatch computations;

(vi) Description of Eligible Customer's transmission system:

- Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by the Transmission Provider
- Operating restrictions needed for reliability
- Operating guides employed by system operators
- Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Network Loads and Resources
- Location of Network Resources described in subsection (v) above
- 10 year projection of system expansions or upgrades
- Transmission System maps that include any proposed expansions or upgrades
- Thermal ratings of Eligible Customer's Control Area ties with other Control Areas;

(vii) Service Commencement Date and the term of the requested Network Integration Transmission Service. The minimum term for Network Integration Transmission Service is one year;

(viii) A statement signed by an authorized officer from or agent of the Network Customer attesting that all of the network resources listed pursuant to Section 29.2(v) satisfy the following conditions:

(1) The Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) the Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis; and

(ix) Any additional information required of the Transmission Customer as specified in the Transmission Provider's planning process established in Attachment K.

Unless the Parties agree to a different time frame, the Transmission Provider must acknowledge the request within ten (10) days of receipt. The acknowledgement must include a date by which a response, including a Service Agreement, will be sent to the Eligible Customer. If an Application fails to meet the requirements of this section, the Transmission Provider shall notify the Eligible Customer requesting service within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, the Transmission Provider will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application without prejudice to the Eligible Customer filing a new or revised Application that fully complies with the requirements of this section. The Eligible Customer will be assigned a new priority consistent with the date of the new or revised Application. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

29.3 Technical Arrangements to be Completed Prior to Commencement of Service

Network Integration Transmission Service shall not commence until the Transmission Provider and the Network Customer, or a third party, have completed installation of all equipment specified under the Network Operating Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the Transmission System. The Transmission Provider shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

29.4 Network Customer Facilities

The provision of Network Integration Transmission Service shall be conditioned upon the Network Customer's constructing, maintaining and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and energy from the Transmission Provider's Transmission System to the Network Customer. The Network Customer shall be solely responsible for constructing or installing all facilities on the Network Customer's side of each such delivery point or interconnection.

29.5 Filing of Service Agreement

The Transmission Provider will file Service Agreements with the Commission in compliance with applicable Commission regulations.

30 Network Resources

30.1 Designation of Network Resources

Network Resources shall include all generation owned, purchased or leased by the Network Customer designated to serve Network Load under the Tariff. Network Resources may not include resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis. Any owned or purchased resources that were serving the Network Customer's loads under firm agreements entered into on or before the Service Commencement Date shall initially be designated as Network Resources until the Network Customer terminates the designation of such resources.

30.2 Designation of New Network Resources

The Network Customer may designate a new Network Resource by providing the Transmission Provider with as much advance notice as practicable. A designation of a new Network Resource must be made through the Transmission Provider's OASIS by a request for modification of service pursuant to an Application under Section 29. This request must include a statement that the new network resource satisfies the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) The Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis. The Network Customer's request will be deemed deficient if it does not include this statement and the Transmission Provider will follow the procedures for a deficient application as described in Section 29.2 of the Tariff.

30.3 Termination of Network Resources

The Network Customer may terminate the designation of all or part of a generating resource as a Network Resource by providing notification to the Transmission Provider through OASIS as soon as reasonably practicable, but not later than the firm scheduling deadline for the period of termination. Any request for termination of Network Resource status must be submitted on OASIS, and should indicate whether the request is for indefinite or temporary termination. A request for indefinite termination of Network Resource status must indicate the date and time that the termination is to be effective, and the identification and capacity of the resource(s) or portions thereof to be indefinitely terminated. A request for temporary termination of Network Resource status must include the following:

(i) Effective date and time of temporary termination;

(ii) Effective date and time of redesignation, following period of temporary termination;

(iii) Identification and capacity of resource(s) or portions thereof to be temporarily terminated;

(iv) Resource description and attestation for redesignating the network resource following the temporary termination, in accordance with Section 30.2; and

(v) Identification of any related transmission service requests to be evaluated concomitantly with the request for temporary termination, such that the requests for undesignation and the request for these related transmission service requests must be approved or denied as a single request. The evaluation of these related transmission service requests must take into account the termination of the network resources identified in (iii) above, as well as all competing transmission service requests of higher priority.

As part of a temporary termination, a Network Customer may only redesignate the same resource that was originally designated, or a portion thereof. Requests to redesignate a different resource and/or a resource with increased capacity will be deemed deficient and the Transmission Provider will follow the procedures for a deficient application as described in Section 29.2 of the Tariff.

30.4 Operation of Network Resources

The Network Customer shall not operate its designated Network Resources located in the Network Customer's or Transmission Provider's Control Area such that the output of those facilities exceeds its designated Network Load, plus Non-Firm Sales delivered pursuant to Part II of the Tariff, plus losses. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of the Transmission Provider to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Transmission System. For all Network Resources not physically connected with the Transmission Provider's Transmission System, the Network Customer may not schedule delivery of energy in excess of the Network Resource's capacity, as specified in the Network Customer's Application pursuant to Section 29, unless the Network Customer supports such delivery within the Transmission Provider's Transmission System by either obtaining Point-to-Point Transmission Service or utilizing secondary service pursuant to Section 28.4. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Network Customer's schedule at the delivery point for a Network Resource not physically interconnected with the Transmission Provider's Transmission System exceeds the Network Resource's designated capacity, excluding energy delivered using secondary service or Point-to-Point Transmission Service.

30.5 Network Customer Redispatch Obligation

As a condition to receiving Network Integration Transmission Service, the Network Customer agrees to redispatch its Network Resources as requested by the Transmission Provider pursuant to Section 33.2. To the extent practical, the redispatch of resources pursuant to this section shall be on a least cost, non-discriminatory basis between all Network Customers, and the Transmission Provider.

30.6 Transmission Arrangements for Network Resources Not Physically Interconnected With The Transmission Provider

The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with the Transmission Provider's Transmission System. The Transmission Provider will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

30.7 Limitation on Designation of Network Resources

The Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff.

30.8 Use of Interface Capacity by the Network Customer

There is no limitation upon a Network Customer's use of the Transmission Provider's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of the Transmission Provider's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

30.9 Network Customer Owned Transmission Facilities

The Network Customer that owns existing transmission facilities that are

integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of the Transmission Provider, to serve its power and transmission customers. For facilities added by the Network Customer subsequent to the [the effective date of a Final Rule in RM05–25–000], the Network Customer shall receive credit for such transmission facilities added if such facilities are integrated into the operations of the Transmission Provider's facilities; provided however, the Network Customer's transmission facilities shall be presumed to be integrated if such transmission facilities, if owned by the Transmission Provider, would be eligible for inclusion in the Transmission Provider's annual transmission revenue requirement as specified in Attachment H. Calculation of any credit under this subsection shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

31 Designation of Network Load

31.1 Network Load

The Network Customer must designate the individual Network Loads on whose behalf the Transmission Provider will provide Network Integration Transmission Service. The Network Loads shall be specified in the Service Agreement.

31.2 New Network Loads Connected With the Transmission Provider

The Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable of the designation of new Network Load that will be added to its Transmission System. A designation of new Network Load must be made through a modification of service pursuant to a new Application. The Transmission Provider will use due diligence to install any transmission facilities required to interconnect a new Network Load designated by the Network Customer. The costs of new facilities required to interconnect a new Network Load shall be determined in accordance with the procedures provided in Section 32.4 and shall be charged to the Network Customer in accordance with Commission policies.

31.3 Network Load Not Physically Interconnected With the Transmission Provider

This section applies to both initial designation pursuant to Section 31.1 and the subsequent addition of new Network Load not physically interconnected with the Transmission Provider. To the extent that the Network Customer desires to obtain transmission service for a load outside the Transmission Provider's Transmission System, the Network Customer shall have the option of (1) electing to include the entire load as Network Load for all purposes under Part III of the Tariff and designating Network Resources in connection with such additional Network Load, or (2) excluding that entire load from its Network Load and purchasing Point-To-Point Transmission Service under Part II of the Tariff. To the extent that the Network Customer gives notice of its intent to add a new Network Load as part of its Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

31.4 New Interconnection Points

To the extent the Network Customer desires to add a new Delivery Point or interconnection point between the Transmission Provider's Transmission System and a Network Load, the Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable.

31.5 Changes in Service Requests

Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Network Integration Transmission Service (*e.g.* the addition of a new Network Resource or designation of a new Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by the Transmission Provider and charged to the Network Customer as reflected in the Service Agreement. However, the Transmission Provider must treat any requested change in Network Integration Transmission Service in a non-discriminatory manner.

31.6 Annual Load and Resource Information Updates

The Network Customer shall provide the Transmission Provider with annual updates of Network Load and Network Resource forecasts consistent with those included in its Application for Network Integration Transmission Service under Part III of the Tariff including, but not limited to, any information provided under section 29.2(ix) pursuant to the Transmission Provider's planning process in Attachment K. The Network Customer also shall provide the Transmission Provider with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Network Load, Network Resources, its transmission system or other aspects of its facilities or operations affecting the Transmission Provider's ability to provide reliable service.

32 Additional Study Procedures for Network Integration Transmission Service Requests

32.1 Notice of Need for System Impact Study

After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. In such cases, the Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest.

32.2 System Impact Study Agreement and Cost Reimbursement

(i) The System Impact Study Agreement will clearly specify the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible

Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the service requests, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 8.

32.3 System Impact Study Procedures

Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify any system constraints and redispatch options, additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement, or the Application shall be deemed terminated and withdrawn.

32.4 Facilities Study Procedures

If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Eligible Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of the cost of any required Network Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Eligible Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Eligible Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request no longer will be a Completed Application and shall be deemed terminated and withdrawn.

32.5 Penalties for Failure To Meet Study Deadlines

Section 19.9 defines penalties that apply for failure to meet the 60-day study completion due diligence deadlines for System Impact Studies and Facilities Studies under Part II of the Tariff. These same requirements and penalties apply to service under Part III of the Tariff.

33 Load Shedding and Curtailments

33.1 Procedures

Prior to the Service Commencement Date, the Transmission Provider and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Network Operating Agreement with the objective of responding to contingencies on the Transmission System and on systems directly and indirectly interconnected with Transmission Provider's Transmission System. The Parties will implement such programs during any period when the Transmission Provider determines that a system contingency exists and such procedures are necessary to alleviate such contingency. The Transmission Provider will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

33.2 Transmission Constraints

During any period when the Transmission Provider determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission Provider's system, the Transmission Provider will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the Transmission Provider's system. To the extent the Transmission Provider determines that the reliability of the Transmission System can be maintained by redispatching resources, the Transmission Provider will initiate procedures pursuant to the Network Operating Agreement to redispatch all Network Resources and the Transmission Provider's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers and any Network Customer's use of the Transmission System to serve its designated Network Load.

33.3 Cost Responsibility for Relieving Transmission Constraints

Whenever the Transmission Provider implements least-cost redispatch procedures in response to a transmission constraint, the Transmission Provider and Network

Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

33.4 Curtailments of Scheduled Deliveries

If a transmission constraint on the Transmission Provider's Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and the Transmission Provider determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with the Network Operating Agreement or pursuant to the Transmission Loading Relief procedures specified in Attachment J.

33.5 Allocation of Curtailments

The Transmission Provider shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by the Transmission Provider and Network Customer in proportion to their respective Load Ratio Shares. The Transmission Provider shall not direct the Network Customer to Curtail schedules to an extent greater than the Transmission Provider would Curtail the Transmission Provider's schedules under similar circumstances.

33.6 Load Shedding

To the extent that a system contingency exists on the Transmission Provider's Transmission System and the Transmission Provider determines that it is necessary for the Transmission Provider and the Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Network Operating Agreement.

33.7 System Reliability

Notwithstanding any other provisions of this Tariff, the Transmission Provider reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Network Integration Transmission Service without liability on the Transmission Provider's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Network Integration Transmission Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the Transmission Provider's Transmission System or on any other system(s) directly or indirectly interconnected with the Transmission Provider's Transmission System, the Transmission Provider, consistent with Good Utility Practice, also may Curtail Network Integration Transmission Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. The Transmission Provider will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Network Integration Transmission Service will be not unduly discriminatory relative to the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

34 Rates and Charges

The Network Customer shall pay the Transmission Provider for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

34.1 Monthly Demand Charge

The Network Customer shall pay a monthly Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth ($1/12$) of the Transmission Provider's Annual Transmission Revenue Requirement specified in Schedule H.

34.2 Determination of Network Customer's Monthly Network Load

The Network Customer's monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with the Transmission Provider under Section 31.3) coincident with the Transmission Provider's Monthly Transmission System Peak.

34.3 Determination of Transmission Provider's Monthly Transmission System Load

The Transmission Provider's monthly Transmission System load is the Transmission Provider's Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to Part II of this Tariff plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers.

34.4 Redispatch Charge

The Network Customer shall pay a Load Ratio Share of any redispatch costs allocated between the Network Customer and the Transmission Provider pursuant to Section 33. To the extent that the Transmission Provider incurs an obligation to the Network Customer for redispatch costs in accordance with Section 33, such amounts shall be credited against the Network Customer's bill for the applicable month.

34.5 Stranded Cost Recovery

The Transmission Provider may seek to recover stranded costs from the Network Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, the Transmission Provider must separately file any proposal to recover stranded costs under Section 205 of the Federal Power Act.

35 Operating Arrangements

35.1 Operation Under the Network Operating Agreement

The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

35.2 Network Operating Agreement

The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Network Customer within the Transmission Provider's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between the Transmission Provider and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the Transmission Provider's Transmission System, interchange schedules, unit outputs for redispatch required under Section 33, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and

operational considerations required for implementation of Part III of the Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network Customer shall either (i) operate as a Control Area under applicable guidelines of the Electric Reliability Organization (ERO) as defined in 18 CFR 39.1, (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with the Transmission Provider, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies the applicable reliability guidelines of the ERO. The Transmission Provider shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment G.

35.3 Network Operating Committee

A Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the Network Operating Agreement. Each Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

Schedule 1—Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 2—Reactive Supply and Voltage Control From Generation or Other Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for such service will be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Control Area operator.

Schedule 3—Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Control Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 4—Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Energy Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. The Transmission Provider may charge a Transmission Customer a penalty for either hourly generator imbalances under Schedule 9 or hourly energy imbalances under this Schedule for the same imbalance, but not both.

The Transmission Provider shall establish charges for energy imbalance based on the deviation bands as follows: (i) Deviations within $+/-1.5$ percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of the month, at 100 percent of incremental or decremental cost; (ii) deviations greater than $+/-1.5$ percent up to 7.5 percent

(or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of incremental cost or 90 percent of decremental cost, and (iii) deviations greater than +/−7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 125 percent of incremental cost or 75 percent of decremental cost.

For purposes of this Schedule, incremental cost and decremental cost represent the Transmission Provider's actual average hourly cost of the last 10 MW dispatched to supply the Transmission Provider's Native Load Customers, based on the replacement cost of fuel, unit heat rates, start-up costs (including any commitment and redispatch costs), incremental operation and maintenance costs, and purchased and interchange power costs and taxes, as applicable.

Schedule 5—Operating Reserve—Spinning Reserve Service

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The amount of and charges for Spinning Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 6—Operating Reserve—Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 7—Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below:

(1) Yearly delivery: one-twelfth of the demand charge of $____/KW of Reserved Capacity per year.

(2) Monthly delivery: $____/KW of Reserved Capacity per month.

(3) Weekly delivery: $____/KW of Reserved Capacity per week.

(4) Daily delivery: $____/KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

(5) Discounts: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

Schedule 8—Non-Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

(1) Monthly delivery: $____/KW of Reserved Capacity per month.

(2) Weekly delivery: $____/KW of Reserved Capacity per week.

(3) Daily delivery: $____/KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

(4) Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $____/MWH. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

(5) Discounts: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

Schedule 9—Generator Imbalance Service

Generator Imbalance Service is provided when a difference occurs between the output of a generator located in the Transmission Provider's Control Area and a delivery schedule from that generator to (1) another

Control Area or (2) a load within the Transmission Provider's Control Area over a single hour. The Transmission Provider must offer this service when Transmission Service is used to deliver energy from a generator located within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Generator Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area Operator. The Transmission Provider may charge a Transmission Customer a penalty for either hourly generator imbalances under this Schedule or hourly energy imbalances under Schedule 4 for the same imbalance, but not both.

The Transmission Provider shall establish charges for generator imbalance based on the deviation bands as follows: (i) Deviations within +/−1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of each month, at 100 percent of incremental or decremental cost, (ii) deviations greater than +/−1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of incremental cost or 90 percent of decremental cost, and (iii) deviations greater than +/−7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled at 125 percent of incremental cost or 75 percent of decremental cost, except that an intermittent resource will be exempt from this deviation band and will pay the deviation band charges for all deviations greater than the larger of 1.5 percent or 2 MW. An intermittent resource, for the limited purpose of this Schedule is an electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints.

For purposes of this Schedule, incremental cost and decremental cost represent the Transmission Provider's actual average hourly cost of the last 10 MW dispatched to supply the Transmission Provider's Native Load Customers, based on the replacement cost of fuel, unit heat rates, start-up costs (including any commitment and redispatch costs), incremental operation and maintenance costs, and purchased and interchange power costs and taxes, as applicable.

Attachment A—Form Of Service Agreement For Firm Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of ________, is entered into, by and between ________ (the Transmission Provider), and ________ (''Transmission Customer'').

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Firm Point-To-Point Transmission Service under the Tariff.

3.0 The Transmission Customer has provided to the Transmission Provider an Application deposit in accordance with the provisions of Section 17.3 of the Tariff.

4.0 Service under this agreement shall commence on the later of (l) the requested service commencement date, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by the parties.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

____

____

____

Transmission Customer:

____

____

____

7.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By:

____

Name

____

Title

____

Date

Transmission Customer:

By:

____

Name

____

Title

____

Date

Specifications for Long-Term Firm Point-to-Point Transmission Service

1.0 Term of Transaction: ________________

Start Date: ________________

Termination Date: ________________

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

____

3.0 Point(s) of Receipt: ________________

Delivering Party: ________________

4.0 Point(s) of Delivery: ________________

Receiving Party: ________________

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity): __

6.0 Designation of party(ies) subject to reciprocal service obligation: ________________

____

____

____

7.0 Name(s) of any Intervening Systems providing transmission service: ____________

____

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge: ________________

____

8.2 System Impact and/or Facilities Study Charge(s):

____

____

8.3 Direct Assignment Facilities Charge: __

____

8.4 Ancillary Services Charges: __________

____

____

____

____

____

____

Attachment A–1—Form of Service Agreement for the Resale, Reassignment or Transfer of Long-Term Firm Point-to-Point Transmission Service

1.0 This Service Agreement, dated as of ________, is entered into, by and between ________ (the Transmission Provider), and ________ (the Assignee).

2.0 The Assignee has been determined by the Transmission Provider to be an Eligible Customer under the Tariff pursuant to which

the transmission service rights to be transferred were originally obtained.

3.0 The terms and conditions for the transaction entered into under this Service Agreement shall be subject to the terms and conditions of Part II of the Transmission Provider's Tariff, except for those terms and conditions negotiated by the Reseller, as identified below, of the reassigned transmission capacity (pursuant to Section 23.1 of this Tariff) and the Assignee and appropriately specified in this Service Agreement. Such negotiated terms and conditions include: contract effective and termination dates, the amount of reassigned capacity or energy, point(s) of receipt and delivery. Changes by the Assignee to the Reseller's Points of Receipt and Points of Delivery will be subject to the provisions of Section 23.2 of this Tariff.

4.0 The Transmission Provider shall credit or charge the Reseller, as appropriate, for any difference between the price reflected in the Assignee's Service Agreement and the Reseller's Service Agreement with the Transmission Provider.

5.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

____

____

____

Assignee:

____

____

____

6.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By:

____

Name

____

Title

____

Date

Assignee:

By:

____

Name

____

Title

____

Date

Specifications for the Resale, Reassignment or Transfer of Long-Term Firm Point-to-Point Transmission Service

1.0 Term of Transaction: ______________

Start Date: ______________

Termination Date: ______________

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates. ______________

____

3.0 Point(s) of Receipt: ______________

Delivering Party: ______________

4.0 Point(s) of Delivery: ______________

Receiving Party: ______________

5.0 Maximum amount of reassigned capacity: ______________

6.0 Designation of party(ies) subject to reciprocal service obligation: ______________

____

____

____

7.0 Name(s) of any Intervening Systems providing transmission service: ______________

____

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge: ______________

____

8.2 System Impact and/or Facilities Study Charge(s):

____

____

8.3 Direct Assignment Facilities Charge: __

____

8.4 Ancillary Services Charges: ______________

____

____

____

____

____

____

9.0 Name of Reseller of the reassigned transmission capacity:

____

Attachment B—Form of Service Agreement for Non-Firm Point-to-Point Transmission Service

1.0 This Service Agreement, dated as of ________, is entered into, by and between ________ (the Transmission Provider), and ________ (Transmission Customer).

2.0 The Transmission Customer has been determined by the Transmission Provider to be a Transmission Customer under Part II of the Tariff and has filed a Completed Application for Non-Firm Point-To-Point Transmission Service in accordance with Section 18.2 of the Tariff.

3.0 Service under this Agreement shall be provided by the Transmission Provider upon request by an authorized representative of the Transmission Customer.

4.0 The Transmission Customer agrees to supply information the Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Non-Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

____

____

____

Transmission Customer:

____

____

____

7.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By:

____

Name

____

Title

____

Date

Transmission Customer:

By:

____

Name

____

Title

____

Date

Attachment C—Methodology To Assess Available Transfer Capability

The Transmission Provider must include, at a minimum, the following information concerning its ATC calculation methodology:

(1) A detailed description of the specific mathematical algorithm used to calculate firm and non-firm ATC (and AFC, if applicable) for its scheduling horizon (same day and real-time), operating horizon (day ahead and pre-schedule) and planning horizon (beyond the operating horizon);

(2) A process flow diagram that illustrates the various steps through which ATC/AFC is calculated; and

(3) A detailed explanation of how each of the ATC components is calculated for both the operating and planning horizons.

(a) For TTC, a Transmission Provider shall: (i) explain its definition of TTC; (ii) explain its TTC calculation methodology; (iii) list the databases used in its TTC assessments; and (iv) explain the assumptions used in its TTC assessments regarding load levels, generation dispatch, and modeling of planned and contingency outages.

(b) For ETC, a transmission provider shall explain: (i) its definition of ETC; (ii) the calculation methodology used to determine the transmission capacity to be set aside for native load (including network load), and non-OATT customers (including, if applicable, an explanation of assumptions on the selection of generators that are modeled in service); (iii) how point-to-point transmission service requests are incorporated; (iv) how rollover rights are accounted for; and (v) its processes for ensuring that non-firm capacity is released

properly (*e.g.*, when real time schedules replace the associated transmission service requests in its real-time calculations).

(c) If a Transmission Provider uses an AFC methodology to calculate ATC, it shall:

(i) explain its definition of AFC; (ii) explain its AFC calculation methodology; (iii) explain its process for converting AFC into ATC for OASIS posting; (iv) list the databases used in its AFC assessments; and (v) explain the assumptions used in its AFC assessments regarding load levels, generation dispatch, and modeling of planned and contingency outages.

(d) For TRM, a Transmission Provider shall explain: (i) its definition of TRM; (ii) its TRM calculation methodology (*e.g.*, its assumptions on load forecast errors, forecast errors in system topology or distribution factors and loop flow sources); (iii) the databases used in its TRM assessments; (iv) the conditions under which the transmission provider uses TRM. A Transmission Provider that does not set aside transfer capability for TRM must so state.

(e) For CBM, the Transmission Provider shall state include a specific and self-contained narrative explanation of its CBM practice, including: (i) an identification of the entity who performs the resource adequacy analysis for CBM determination; (ii) the methodology used to perform generation reliability assessments (*e.g.*, probabilistic or deterministic); (iii) an explanation of whether the assessment method reflects a specific regional practice; (iv) the assumptions used in this assessment; and (v) the basis for the selection of paths on which CBM is set aside.

(f) In addition, for CBM, a Transmission Provider shall: (i) explain its definition of CBM; (ii) list the databases used in its CBM calculations; and (iii) demonstrate that there is no double-counting of contingency outages when performing CBM, TTC, and TRM calculations.

(g) The Transmission Provider shall explain its procedures for allowing the use of CBM during emergencies (with an explanation of what constitutes an emergency, the entities that are permitted to use CBM during emergencies and the procedures which must be followed by the transmission providers' merchant function and other load-serving entities when they need to access CBM). If the Transmission Provider's practice is not to set aside transfer capability for CBM, it shall so state.

Attachment D—Methodology for Completing a System Impact Study

To be filed by the Transmission Provider

Attachment E—Index of Point-To-Point Transmission Service Customers

Customer
Date of Service Agreement

Attachment F—Service Agreement for Network Integration Transmission Service

To be filed by the Transmission Provider

Attachment G—Network Operating Agreement

To be filed by the Transmission Provider

Attachment H—Annual Transmission Revenue Requirement for Network Integration Transmission Service

1. The Annual Transmission Revenue Requirement for purposes of the Network Integration Transmission Service shall be ________.

2. The amount in (1) shall be effective until amended by the Transmission Provider or modified by the Commission.

Attachment I—Index of Network Integration Transmission Service Customers

Customer
Date of Service Agreement

Attachment J—Procedures for Addressing Parallel Flows

To be filed by the Transmission Provider

Attachment K—Transmission Planning Process

The Transmission Provider shall establish a coordinated, open and transparent planning process with its Network and Firm Point-to-Point Transmission Customers and other interested parties, including the coordination of such planning with interconnected systems within its region, to ensure that the Transmission System is planned to meet the needs of both the Transmission Provider and its Network and Firm Point-to-Point Transmission Customers on a comparable and nondiscriminatory basis. The Transmission Provider's coordinated, open and transparent planning process shall be provided as an attachment to the Transmission Provider's Tariff.

The Transmission Provider's planning process shall satisfy the following nine principles, as defined in the Final Rule in Docket No. RM05–25–000: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new projects. The planning process shall also provide a mechanism for the recovery and allocation of planning costs consistent with the Final Rule in Docket No. RM05–25–000.

The Transmission Provider's planning process must include sufficient detail to enable Transmission Customers to understand:

(i) The process for consulting with customers and neighboring transmission providers;

(ii) The notice procedures and anticipated frequency of meetings;

(iii) The methodology, criteria, and processes used to develop transmission plans;

(iv) The method of disclosure of criteria, assumptions and data underlying transmission system plans;

(v) The obligations of and methods for customers to submit data to the transmission provider;

(vi) The dispute resolution process;

(vii) The transmission provider's study procedures for economic upgrades to address congestion or the integration of new resources; and

(viii) The relevant cost allocation procedures or principles.

Attachment L—Creditworthiness Procedures

For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, the Transmission Provider may require reasonable credit review procedures. This review shall be made in accordance with standard commercial practices and must specify quantitative and qualitative criteria to determine the level of secured and unsecured credit.

The Transmission Provider may require the Transmission Customer to provide and maintain in effect during the term of the Service Agreement, an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under the Tariff, or an alternative form of security proposed by the Transmission Customer and acceptable to the Transmission Provider and consistent with commercial practices established by the Uniform Commercial Code that protects the Transmission Provider against the risk of non-payment.

Additionally, the Transmission Provider must include, at a minimum, the following information concerning its creditworthiness procedures:

(1) a summary of the procedure for determining the level of secured and unsecured credit;

(2) a list of the acceptable types of collateral/security;

(3) a procedure for providing customers with reasonable notice of changes in credit levels and collateral requirements;

(4) a procedure for providing customers, upon request, a written explanation for any change in credit levels or collateral requirements;

(5) a reasonable opportunity to contest determinations of credit levels or collateral requirements; and

(6) a reasonable opportunity to post additional collateral, including curing any non-creditworthy determination.

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Thursday,

March 15, 2007

Part III

Department of Housing and Urban Development

24 CFR Parts 91 and 570

Timeliness Expenditure Standards for the Insular Areas Program; Final Rule

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

24 CFR Parts 91 and 570

[Docket No. FR–5012–F–02]

RIN 2501–AD15

Timeliness Expenditure Standards for the Insular Areas Program

AGENCY: Office of the Assistant Secretary for Community Planning and Development, HUD.

ACTION: Final rule.

SUMMARY: This final rule implements regulatory timeliness standards for the Insular Areas Program, as established by the Housing and Community Development Act of 1974. The expenditure standards will ensure that grantees carry out their programs in a timely manner. The standards take into consideration and reflect the unique circumstances faced by Insular Area grantees in their ability to expend CDBG allocations. The final rule provides that an Insular Area grantee may submit an abbreviated consolidated plan rather than a full consolidated plan. This final rule also makes technical and conforming changes to the Insular Areas program. The final rule follows publication of an August 7, 2006, proposed rule on which HUD did not receive any public comments. Accordingly, HUD is adopting the August 7, 2006, proposed rule without change.

DATES: *Effective Date:* April 16, 2007.

FOR FURTHER INFORMATION CONTACT: Stephen Rhodeside, Senior Program Officer, State and Small Cities Division, Office of Block Grant Assistance, Office of Community Planning and Development, Department of Housing and Urban Development, 451 Seventh Street, SW., Room 7184, Washington, DC 20410–7000, telephone (202) 708–1322 (this is not a toll-free number). Individuals with speech or hearing impairments may access this number through TTY by calling the toll-free Federal Information Relay Service at (800) 877–8339.

SUPPLEMENTARY INFORMATION:

I. Background

On August 7, 2006, HUD published a proposed rule (71 FR 44860) for public comment to establish timeliness standards and procedures for the reallocation of funds for the Insular Areas Program. In addition, the August 7, 2006, rule proposed to provide that an Insular Area grantee may submit an abbreviated consolidated plan that is appropriate to the types and amounts of assistance sought from HUD, instead of a full consolidated plan. The proposed rule also sought to make technical and conforming changes to the regulations.

The Insular Areas program is a component of the Community Development Block Grant (CDBG) program, authorized by the Housing and Community Development Act of 1974 (HCD Act) (42 U.S.C. 5301, *et seq.*). Under the CDBG program, Insular Area grantees are provided flexible funding to develop and implement community and economic development strategies that primarily benefit low- and moderate-income individuals.

The August 7, 2006, rule proposed timeliness standards for the Insular Areas Program. Under the proposed standards, the amount of grant funds available but undisbursed 60 days prior to the conclusion of the Insular Area grantee's most recent program year must be no more than two times the amount of the Insular Area grantee's most recent grant. If the grantee fails to demonstrate to HUD's satisfaction that the lack of timeliness has resulted from factors beyond the grantee's reasonable control, the grantee shall be deemed to be untimely. A grantee that has less than two times its most recent grant in its CDBG line of credit 60 days prior to the conclusion of its most recent program year shall also be deemed to be untimely if the amount of CDBG program income the recipient has on hand at that time, together with the amount of funds in its CDBG line of credit, exceeds twice the amount of the grantee's most recent grant, unless the grantee is able to demonstrate to HUD's satisfaction that the lack of timeliness has resulted from factors beyond the grantee's reasonable control.

In determining the corrective action for untimely expenditure, HUD will consider the likelihood that the recipient will expend a sufficient amount of funds over the next program year to bring the grantee into compliance with the timeliness requirements. The first timeliness review under these standards will take place 60 days prior to the conclusion of the 2006 funding year, which would take place on August 2, 2007, for Insular Area grantees that do not change their program year start dates. Failure to meet the standards may cause HUD to reduce the next grant by 100 percent of the amount in excess of twice the Insular Area grantee's most recent CDBG grant, unless HUD determines that the untimeliness resulted from factors outside of the grantee's reasonable control. The earliest that HUD will reduce grants under this final rule will be in Fiscal Year (FY) 2008, should an Insular Area grantee be untimely 60 days prior to the conclusion of its FY 2006 and FY 2007 program years.

Additionally, HUD proposed to add a provision that would allow funds to be reallocated to the remaining eligible Insular Areas on a pro rata basis should an Insular Area grantee have its funding reduced for failing to submit a final statement for CDBG funds. The proposed rule also addressed the issue of Insular Area grantees' submission of abbreviated consolidated plans. Abbreviated consolidated plans submitted by Insular Areas grantees will be considered to be full consolidated plans, provided the Insular Area grantee complies with the submissions, certifications, amendments, and performance reports requirements of § 570.440 and citizen participation requirements of § 570.441. However, if submission of a full consolidated plan would help a grantee integrate its CDBG, HOME and Emergency Shelter Grant programs, the grantee should strongly consider submitting a full consolidated plan. Various technical changes were proposed to reflect statutory amendments, remove outdated cross-references, and delete provisions that are no longer required or applicable.

For more detailed information regarding the regulatory changes, please refer to the preamble of the August 7, 2006, proposed rule.

II. This Final Rule

This final rule follows the publication of the August 7, 2006, proposed rule. The public comment period on the proposed rule closed on October 6, 2006. HUD did not receive any public comments on the proposed rule. HUD, therefore, is issuing this final rule without change from the proposed rule.

III. Findings and Certifications

Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (2 U.S.C. 1531–1538) (UMRA) establishes requirements for federal agencies to assess the effects of their regulatory actions on state, local, and tribal governments and the private sector. This final rule does not impose any federal mandates on any state, local, or tribal government or the private sector within the meaning of UMRA.

Executive Order 13132, Federalism

Executive Order 13132 (entitled ''Federalism'') prohibits, to the extent practicable and permitted by law, an agency from promulgating a regulation that has federalism implications and either imposes substantial direct

compliance costs on state and local governments and is not required by statute, or preempts state law, unless the relevant requirements of section 6 of the executive order are met. This rule does not have federalism implications and does not impose substantial direct compliance costs on state and local governments or preempt state law within the meaning of the executive order.

Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) (5 U.S.C. 601 *et seq.*) generally requires an agency to conduct regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. This rule will not have a significant economic impact on a substantial number of small entities because the rule only codifies in HUD's regulations procedures that will enable the Department to enforce its timeliness policy for the Insular Areas Program. As such, the rule does not significantly differ from the current status in terms of the impact on the number of entities, the amount of funding, or the governing requirements applicable. Therefore, the undersigned certifies that this final rule will not have a significant economic impact on a substantial number of small entities, and an initial regulatory flexibility analysis is not required.

Environmental Impact

A Finding of No Significant Impact with respect to the environment was made at the proposed rule stage in accordance with HUD regulations at 24 CFR part 50, which implement section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332(2)(C)). The Finding of No Significant Impact remains applicable to this final rule and is available for public inspection between the hours of 8 a.m. and 5 p.m. weekdays in the Regulations Division, Office of General Counsel, Department of Housing and Urban Development, 451 Seventh Street, SW., Room 10276, Washington, DC 20410–0500. Due to security measures at the HUD Headquarters building, please schedule an appointment to review the finding by calling the Regulations Division at (202) 708–3055 (this is not a toll-free number). Hearing or speech-challenged individuals may access this number through TTY by calling the toll-free Federal Information Relay Service at (800) 877–8339.

Catalog of Federal Domestic Assistance

The Catalog of Federal Domestic Assistance number for the Insular Areas Program is 14.225.

List of Subjects

24 CFR Part 91

Aged, Grant programs-housing and community development, Homeless, Individuals with disabilities, Low and moderate income housing, Reporting and recordkeeping requirements.

24 CFR Part 570

Administrative practice and procedure, American Samoa, Community development block grants, Grant programs—education, Grant programs—housing and community development, Guam, Indians, Lead poisoning, Loan programs—housing and community development, Low and moderate income housing, New communities, Northern Mariana Islands, Pacific Islands Trust Territory, Pockets of poverty, Puerto Rico, Reporting and recordkeeping requirements, Small cities, Student aid, Virgin Islands.

■ Accordingly, HUD amends 24 CFR parts 91 and 570 as follows:

PART 91—CONSOLIDATED SUBMISSIONS FOR COMMUNITY PLANNING AND DEVELOPMENT PROGRAMS

■ 1. The authority citation for 24 CFR part 91 continues to read as follows:

Authority: 42 U.S.C. 3535(d), 3601–3619, 5301–5315, 11331–11388, 12701–12711, 12741–12756, and 12901–12912.

■ 2. In § 91.235 revise paragraphs (a), (b)(3), and (e) and add paragraph (c)(4) to read as follows:

§ 91.235 Special case; abbreviated consolidated plan.

(a) *Who may submit an abbreviated plan?* A jurisdiction that is not a CDBG entitlement community under 24 CFR part 570, subpart D, and is not expected to be a participating jurisdiction in the HOME program under 24 CFR part 92, as well as an Insular Area that is a HOME or CDBG grantee, may submit an abbreviated consolidated plan that is appropriate to the types and amounts of assistance sought from HUD, instead of a full consolidated plan.

(b) * * *

(3) *Limitation.* For the HOME program, an abbreviated consolidated plan is permitted only with respect to reallocations to other than participating jurisdictions (see 24 CFR part 92, subpart J), and for Insular Area grantees that submit an abbreviated consolidated plan pursuant to 24 CFR 570.440. For the CDBG program, an abbreviated plan may be submitted for the HUD-administered Small Cities program (except that an abbreviated plan may not be submitted for the HUD-administered Small Cities program in the state of Hawaii), and for Insular Area grantees pursuant to 24 CFR 570.440.

(c) * * *

(4) *Submissions, Certifications, Amendments, and Performance Reports.* An Insular Area grantee that submits an abbreviated consolidated plan under this section must comply with the submission, certification, amendment, and performance report requirements of 24 CFR 570.440. This includes certification that the grantee will affirmatively further fair housing, which means it will conduct an analysis of impediments to fair housing choice and undertake other activities required for fair housing planning, in accordance with 24 CFR 91.225(a)(1) and 570.601(a)(2).

* * * * *

(e) *Citizen Participation.* An Insular Area grantee that submits an abbreviated consolidated plan under this section must comply with the citizen participation requirements of 24 CFR 570.441.

* * * * *

PART 570—COMMUNITY DEVELOPMENT BLOCK GRANTS

■ 3. The authority citation for 24 CFR part 570 continues to read as follows:

Authority: 42 U.S.C. 3535(d) and 5301–5320.

■ 4. Revise § 570.209(b)(2)(i) to read as follows:

§ 570.209 Guidelines for evaluating and selecting economic development projects.

* * * * *

(b) * * *

(2) *Applying the aggregate standards.* (i) A metropolitan city, an urban county, or an Insular Area shall apply the aggregate standards under paragraph (b)(1) of this section to all applicable activities for which CDBG funds are first obligated within each single CDBG program year, without regard to the source year of the funds used for the activities. For Insular Areas, the preceding sentence applies to grants received in program years after Fiscal Year 2004. A grantee under the HUD-administered Small Cities program in New York, or Insular Areas CDBG programs grants prior to Fiscal Year 2005, shall apply the aggregate standards under paragraph (b)(1) of this section to all funds obligated for applicable activities from a given grant;

program income obligated for applicable activities will, for these purposes, be aggregated with the most recent open grant. For any time period in which a community has no open HUD-administered grant, the aggregate standards shall be applied to all applicable activities for which program income is obligated during that period.

* * * * *

■ 5. Add § 570.442 to subpart F to read as follows:

§ 570.442 Reallocations-Insular Areas.

(a) Any Insular Area funds that become available as a result of reductions under subpart O of this part, shall be reallocated in the same or future fiscal year to any remaining eligible Insular Area grantees pro rata according to population.

(b) Any Insular Area grant funds for a fiscal year reserved for an applicant that chooses not to submit a final statement in accordance with § 570.440 to receive such funds, shall be reallocated in the same or future fiscal year to any remaining eligible Insular Area grantees pro rata according to population.

(c) No amounts shall be reallocated under this section in any fiscal year to any applicant whose grant amount in such fiscal year was reduced under subpart O of this part or who did not submit a final statement in accordance with § 570.440 for that fiscal year.

(d) Insular Area grantees receiving additional funds under this section will be evaluated for timeliness under § 570.902 based upon the original grant amount plus the additional funds received. Accordingly, references in § 570.902 to an Insular Area's grant amount for its current program year include such additional funds, and references to unexpended or undisbursed funds include such additional funds.

■ 6. Revise § 570.600(a) to read as follows:

§ 570.600 General.

(a) This subpart K enumerates laws that the Secretary will treat as applicable to grants made under section 106 of the Act, other than grants to states made pursuant to section 106(d) of the Act, for purposes of the Secretary's determinations under section 104(e)(1) of the Act, including statutes expressly made applicable by the Act and certain other statutes and Executive Orders for which the Secretary has enforcement responsibility. This subpart K applies to grants made under the Insular Areas Program in § 570.405 and § 570.440 with the exception of § 570.612. The absence of mention herein of any other statute for which the Secretary does not have direct enforcement responsibility is not intended to be taken as an indication that, in the Secretary's opinion, such statute or Executive Order is not applicable to activities assisted under the Act. For laws that the Secretary will treat as applicable to grants made to states under section 106(d) of the Act for purposes of the determination required to be made by the Secretary pursuant to section 104(e)(2) of the Act, see § 570.487.

* * * * *

■ 7. In § 570.900, revise paragraphs (a)(1) and (b)(1) to read as follows:

§ 570.900 General.

(a) *Performance review authorities*—(1) *Entitlement, Insular Areas, and HUD-administered Small Cities performance reviews.* Section 104(e)(1) of the Act requires that the Secretary shall, at least on an annual basis, make such reviews and audits as may be necessary or appropriate to determine whether the recipient has carried out its activities in a timely manner, whether the recipient has carried out those activities and its certifications in accordance with the requirements and the primary objectives of the Act and with other applicable laws, and whether the recipient has a continuing capacity to carry out those activities in a timely manner.

* * * * *

(b) * * *

(1) The Department will determine the performance of each entitlement, Insular Areas, and HUD-administered small cities recipient in accordance with section 104(e)(1) of the Act by reviewing for compliance with the requirements described in § 570.901 and by applying the performance criteria described in §§ 570.902 and 570.903 relative to carrying out activities in a timely manner. The review criteria in § 570.904 will be used to assist in determining if the recipient's program is being carried out in compliance with civil rights requirements.

* * * * *

■ 8. In § 570.901, revise the introductory paragraph, redesignate existing paragraphs (f), (g), and (h), as paragraphs (g), (h), and (i) respectively, and add a new paragraph (f) to read as follows:

§ 570.901 Review for compliance with the primary and national objectives and other program requirements.

HUD will review each entitlement, Insular Areas, and HUD-administered small cities recipient's program to determine if the recipient has carried out its activities and certifications in compliance with:

* * * * *

(f) For Insular Areas Program grants only, the application and amendment requirements at § 570.440, the citizen participation requirements at § 570.441, the displacement policy requirements of § 570.606, and the lead-based paint requirements of 24 CFR 35.940;

* * * * *

■ 9. In § 570.902, revise the introductory paragraph, and add a new paragraph (c) to read as follows:

§ 570.902 Review to determine if CDBG-funded activities are being carried out in a timely manner.

HUD will review the performance of each entitlement, HUD-administered small cities, and Insular Areas recipient to determine whether each recipient is carrying out its CDBG-assisted activities in a timely manner.

* * * * *

(c) *Insular Areas recipients.* (1) Before the funding of the next annual grant and absent contrary evidence satisfactory to HUD, HUD will consider an Insular Areas recipient to be failing to carry out its CDBG activities in a timely manner if:

(i) Sixty days prior to the end of the grantee's current program year, the amount of Insular Area grant funds available to the recipient under grant agreements but undisbursed by the U.S. Treasury is more than 2.0 times the Insular Area's grant amount for its current program year; and

(ii) The grantee fails to demonstrate to HUD's satisfaction that the lack of timeliness has resulted from factors beyond the grantee's reasonable control.

(2) Notwithstanding that the amount of funds in the line of credit indicates that the Insular Area recipient is carrying out its activities in a timely manner pursuant to paragraph (c)(1) of this section, HUD may determine that the recipient is not carrying out its activities in a timely manner if:

(i) The amount of CDBG program income the recipient has on hand 60 days prior to the end of its current program year, together with the amount of funds in its CDBG line of credit, exceeds 2.0 times the Insular Area's grant amount for its current program year; and

(ii) The grantee fails to demonstrate to HUD's satisfaction that the lack of timeliness has resulted from factors beyond the grantee's reasonable control.

(3) In determining the appropriate corrective action to take with respect to

a HUD determination that a recipient is not carrying out its activities in a timely manner pursuant to paragraphs (c)(1) or (c)(2) of this section, HUD will consider the likelihood that the recipient will expend a sufficient amount of funds over the next program year to reduce the amount of unexpended funds to a level that will fall within the standards described in paragraphs (c)(1) and (2) of this section when HUD next measures the grantee's timeliness performance. For these purposes, HUD will take into account the extent to which funds on hand have been obligated by the recipient and its sub-recipients for specific activities at the time the finding is made and other relevant information.

(4) If a recipient is determined to be untimely pursuant to paragraphs (c)(1) or (c)(2) of this section in one year, and the recipient is again determined to be untimely in the following year, HUD may reduce the recipient's next grant by 100 percent of the amount in excess of twice the Insular Area's most recent CDBG grant, unless HUD determines that the untimeliness resulted from factors outside of the grantee's reasonable control.

(5) The first review under paragraphs (c)(1) and (c)(2) of this section will take place 60 days prior to the conclusion of the Fiscal Year 2006 program year.

■ 10. In § 570.903, revise the introductory paragraph, paragraph (a), and remove paragraph (d) to read as follows:

§ 570.903 Review to determine if the recipient is meeting its consolidated plan responsibilities.

The consolidated plan, action plan, and amendment submission requirements referred to in this section are in 24 CFR part 91. For the purpose of this section, the term consolidated plan includes an abbreviated consolidated plan that is submitted pursuant to 24 CFR 91.235.

(a) *Review timing and purpose.* HUD will review the consolidated plan performance of each entitlement, Insular Areas, and Hawaii HUD-administered Small Cities grant recipient prior to acceptance of a grant recipient's annual certification under 24 CFR 91.225(b)(3) to determine whether the recipient followed its HUD-approved consolidated plan for the most recently completed program year, and whether activities assisted with CDBG funds during that period were consistent with that consolidated plan, except that grantees are not bound by the consolidated plan with respect to the use or distribution of CDBG funds to meet non-housing community development needs.

* * * * *

■ 11. In § 570.910, revise paragraphs (b)(2)(iii) and (b)(8) to read as follows:

§ 570.910 Corrective and remedial actions.

* * * * *

(b) * * *

(2) * * *

(iii) For entitlement and Insular Areas recipients, canceling or revising affected activities that are no longer feasible to implement due to the deficiency and re-programming funds from such affected activities to other eligible activities (pursuant to the citizen participation requirements in 24 CFR part 91); or

* * * * *

(8) In the case of an entitlement or Insular Areas recipient, condition the use of funds from a succeeding fiscal year's allocation upon appropriate corrective action by the recipient. The failure of the recipient to undertake the actions specified in the condition may result in a reduction, pursuant to § 570.911, of the entitlement or Insular Areas recipient's annual grant by up to the amount conditionally granted.

■ 12. Revise § 570.911(b) to read as follows:

§ 570.911 Reduction, withdrawal, or adjustment of a grant or other appropriate action.

* * * * *

(b) *Entitlement and Insular Areas grants.* Consistent with the procedures described in § 570.900(b), the Secretary may make a reduction in the entitlement or insular areas grant amount either for the succeeding program year or, if the grant had been conditioned, up to the amount that had been conditioned. The amount of the reduction shall be based on the severity of the deficiency and may be for the entire grant amount.

* * * * *

Dated: March 7, 2007.

Pamela H. Patenaude,

Assistant Secretary for Community Planning and Development.

[FR Doc. E7–4681 Filed 3–14–07; 8:45 am]

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Federal Register

Thursday,

March 15, 2007

Part IV

Department of Housing and Urban Development

24 CFR Part 15

Revisions to the Public Access to HUD Records Under the Freedom of Information Act (FOIA) Regulations; Final Rule

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

24 CFR Part 15

[Docket No. FR–5069–F–02]

RIN 2501–AD22

Revisions to the Public Access to HUD Records Under the Freedom of Information Act (FOIA) Regulations

AGENCY: Office of the Secretary, HUD.

ACTION: Final rule.

SUMMARY: This final rule clarifies and explains the procedures to be followed by requesters seeking a waiver or a reduction of fees under the Freedom of Information Act (FOIA). This final rule describes the information that must be included in a FOIA request and the demonstrations that must be made in order for a waiver or reduction of fees to be granted. This final rule also revises the FOIA fee schedule, clarifies the time at which HUD will begin processing a FOIA request, and modifies HUD's policy on the use of outside contractors to fulfill FOIA requests. HUD undertook this effort in order to make the regulations governing fee waivers more informative and helpful in accordance with the President's recently issued Executive Order 13392, ''Improving Agency Disclosure of Information.'' This final rule also makes technical and conforming changes to reflect the realignment of FOIA correspondence processing functions within HUD, to correct HUD's definition of ''representative of the news media requester'' to ensure conformance with the Office of Management and Budget (OMB) Fee Guidelines, and to update a cross-reference to time limits applicable to HUD for responding to a FOIA request. This final rule follows publication of an October 5, 2006, proposed rule on which HUD received one public comment.

DATES: *Effective Date:* April 16, 2007.

FOR FURTHER INFORMATION CONTACT: Vicky Lewis, Assistant Executive Secretary, Freedom of Information Act (FOIA) Office, Office of the Executive Secretariat, Office of Administration, Department of Housing and Urban Development, 451 Seventh Street, SW., Room 10139, Washington, DC 20410–5000; telephone (202) 708–3054 (this is not a toll-free number). Persons with hearing or speech impairments may access this number via TTY by calling the toll-free Federal Information Relay Service at 1–(800) 877–8339.

SUPPLEMENTARY INFORMATION:

I. Background

On December 14, 2005, President Bush issued Executive Order 13392, entitled ''Improving Agency Disclosure of Information,'' which acknowledged the importance of participation by an informed citizenry in the effective functioning of our constitutional democracy. Executive Order 13392 was published in the **Federal Register** on December 19, 2005 (70 FR 75373). The Freedom of Information Act (5 U.S.C. 552) (FOIA) provides the means by which the public can obtain information regarding federal agencies. Under FOIA, the public can request records from any agency, which the agency must provide, subject to certain exemptions and statutory exclusions.

HUD's regulations at 24 CFR part 15, entitled ''Public Access to HUD Records under the Freedom of Information Act and Testimony and Production of Information by HUD Employees,'' describe the policies and procedures governing public access to HUD records under FOIA. Those regulations describe how the public is to make a FOIA request, what must be included in the request, how the request will be processed, any applicable fees that will be charged, and the process for appealing a denial of a request or a fee determination.

II. The October 5, 2006, Proposed Rule

On October 5, 2006 (71 FR 58994), HUD published a proposed rule to respond to Executive Order 13392. This Executive Order has served as an impetus for each agency to review its FOIA regulations to determine whether its regulations are as helpful as they can be, especially since these regulations reach out to the public generally and are not specific to participants in particular government programs. HUD issued the proposed rule to amend HUD's regulations at 24 CFR part 15 in order to clarify and explain the procedures to be followed by requesters seeking a waiver or reduction of fees under FOIA. HUD also proposed to revise the FOIA fee schedule, clarify the time at which HUD would begin processing a FOIA request, and modify HUD's policy on the use of outside contractors to fulfill FOIA requests. For more detailed information regarding the regulatory changes, please refer to the preamble of the October 5, 2006, proposed rule.

III. This Final Rule; Discussion of Public Comments Received on the October 5, 2006, Proposed Rule

This final rule follows publication of the October 5, 2006, proposed rule. The public comment period on the proposed rule closed on December 4, 2006. HUD received one public comment in response to the proposed rule. The commenter expressed support for FOIA and for the proposed rule, and stated that the proposed changes would allow for a better and easier understanding of requests for fee waivers or reductions. HUD appreciates the commenter's interest in the proposed rule. This final rule adopts the proposed regulatory changes contained in the October 5, 2006, proposed rule without change.

IV. Technical and Conforming Changes

In addition to adopting the revisions and amendments outlined in the proposed rule, this final rule makes technical and conforming changes to §§ 15.103, 15.106, and 15.110 to reflect the realignment of HUD's FOIA processing functions, to correct HUD's definition of ''representative of the news media requester,'' and to update a cross-reference to time limits for HUD to respond to a FOIA request.

Executive Order 13392 required Federal agencies to develop agency-specific plans to ensure the efficient and timely administration of FOIA requests. Such plans were to include specific activities that the agency would implement to eliminate or reduce the agency's FOIA backlog, and activities that would increase public awareness of the agency's FOIA processing. HUD submitted its plan to OMB and the Attorney General on June 14, 2006. (See *http://www.hud.gov/offices/ogc/foia/hudfoiaplanfinal.pdf.*) An integral part of HUD's plan is the realignment of FOIA processing functions from the Office of General Counsel to the Office of the Executive Secretariat in the Office of Administration. The realignment of FOIA processing functions will improve the efficiency and consistency of HUD's FOIA operations. This final rule updates HUD's FOIA regulations at § 15.103 (which describes the procedures for obtaining records from HUD) and § 15.106 (which describes how HUD will respond to requests for records) by replacing outdated references to the Office of General Counsel with references to the Office of Administration.

In addition to the conforming changes described above, HUD has also taken the opportunity afforded by this final rule to correct two technical errors in its FOIA regulations. Section 552(a)(4)(A)(i) of FOIA requires federal agencies to conform their fee schedules to the uniform schedule of fees developed by the Office of Management and Budget (OMB). (*See* ''Uniform Freedom of Information Act Fee Schedule and Guidelines'' published by OMB in the

Federal Register on March 27, 1987 (52 FR 10012)). HUD's definition of ''representative of the news media requester'' is not in conformance with the OMB uniform fee guidelines. Specifically, § 15.110(a)(4) defines a representative of a news media requester as someone who gathers news for an entity that is ''primarily'' organized and operated to publish or broadcast news to the public. The OMB uniform guidelines, however, do not use the word ''primarily'' in the corresponding definition. (See 52 FR 10018). This final rule makes the necessary correction to § 15.110(a)(4) by removing the word ''primarily'' from the definition of news media requester.

This final rule also updates a cross-reference in § 15.106(b). Presently, the cross-reference in § 15.106(b) is to ''the time limit described in § 15.103.'' However, time limitations are discussed in § 15.104. Therefore, the cross-reference should be to time limits described in § 15.104.

V. Findings and Certifications

Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) (5 U.S.C. 601 *et seq.*) generally requires an agency to conduct a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. The regulatory amendments made by this final rule are procedural and explanatory in nature. The FOIA statute establishes criteria by which waivers of fees or reduction of fees may be obtained for a FOIA request. Furthermore, the fees charged under this rule are limited by FOIA to direct costs of searching for, reviewing, and duplicating the records processed for requesters and are not economically significant.

Accordingly, the undersigned certifies that this rule will not have a significant economic impact on a substantial number of small entities.

Environmental Impact

This final rule does not direct, provide for assistance or loan and mortgage insurance for, or otherwise govern or regulate, real property acquisition, disposition, leasing, rehabilitation, alteration, demolition, or new construction, or establish, revise, or provide for standards for construction or construction materials, manufactured housing, or occupancy. Accordingly, under 24 CFR 50.19(c)(1), this final rule is categorically excluded from the requirements of the National Environmental Policy Act (42 U.S.C. 4321 *et seq.*).

Executive Order 13132, Federalism

Executive Order 13132 (entitled ''Federalism'') prohibits an agency from publishing any rule that has federalism implications if the rule either imposes substantial direct compliance costs on state and local governments and is not required by statute, or the rule preempts state law, unless the agency meets the consultation and funding requirements of section 6 of the Executive Order. This final rule does not have federalism implications and does not impose substantial direct compliance costs on state and local governments or preempt state law within the meaning of the Executive Order.

Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (2 U.S.C.1531–1538) (UMRA) establishes requirements for Federal agencies to assess the effects of their regulatory actions on state, local, and tribal governments, and on the private sector. This final rule does not impose any Federal mandates on any State, local, or tribal governments, or on the private sector, within the meaning of UMRA.

List of Subjects in 24 CFR Part 15

Classified information, Courts, Freedom of information, Government employees, Reporting and recordkeeping requirements.

■ Accordingly, for the reasons discussed in the preamble, HUD amends 24 CFR part 15 to read as follows:

PART 15—PUBLIC ACCESS TO HUD RECORDS UNDER THE FREEDOM OF INFORMATION ACT AND TESTIMONY AND PRODUCTION OF INFORMATION BY HUD EMPLOYEES

■ 1. The authority citation for part 15 continues to read as follows:

Authority: 42 U.S.C. 3535(d).

■ 2. In § 15.103, revise the first sentence of paragraph (c) and paragraph (d)(4) to read as follows:

§ 15.103 How can I get other records from HUD?

* * * * *

(c) *Records located in HUD headquarters.* If you are submitting a request for records located in HUD Headquarters, you should deliver or mail your request to the FOIA Office, Office of the Executive Secretariat in the Office of Administration. * * *

(d) * * *

(4) *State your agreement to pay the fee.* You may specify a dollar amount above which you want HUD to consult with you before you will agree to pay the fee. If you are seeking a waiver or reduction of fees, you must include such a request at the same time as your request for disclosure, and you must describe how the disclosure of the requested information is in the public interest and not primarily in the commercial interest of the requester (see § 15.110(h));

* * * * *

■ 3. In § 15.106, revise paragraph (a), paragraph (b) introductory text, and the second sentence of paragraph (b)(2) to read as follows:

§ 15.106 How will HUD respond to my request?

(a) *Who will respond to my request?* (1) The FOIA Office of the Office of the Executive Secretariat in the Office of Administration in HUD Headquarters and the FOIA liaisons in each HUD Field Office are authorized to release copies of any HUD records unless disclosure is clearly not appropriate under FOIA.

(2) The FOIA Office of the Office of the Executive Secretariat in the Office of Administration in HUD Headquarters and the FOIA liaisons in each HUD Field Office may deny a request for a record in accordance with the provisions of FOIA and this part.

(b) *What type of response will I receive?* Within the time limit described in § 15.104, HUD will either:

* * * * *

(2) * * * Any denial or partial denial of a requested record must be concurred in by the FOIA Office of the Office of the Executive Secretariat in the Office of Administration in HUD Headquarters, by counsel in the Field Offices, or by counsel in HUD's Departmental Enforcement Center Satellite Offices. * * *

* * * * *

■ 4. Amend § 15.110 as follows:

■ a. Revise paragraph (b)(4)(i);

■ b. Revise the chart captioned ''FOIA Fee Schedule'' in paragraph (c);

■ c. Revise paragraphs (h) and (i); and

■ d. In paragraph (k), remove the first three sentences and add two new sentences in their place to read as follows:

§ 15.110 What fees will HUD charge?

* * * * *

(b) * * *

(4) * * *

(i) You are a representative of the news media requester if you actively gather news for an entity that is organized and operated to publish or broadcast news to the public.

* * * * *

(c) * * *

FOIA FEE SCHEDULE

Activity	Rate	Commercial use requester	News media, educational research, or scientific research requester	Other requester
(1) Professional search	Actual salary rate of employee involved, plus 16 percent of salary rate.	Applies	Does not apply	Applies. No charge for first two hours of cumulative search time.
(2) Professional review	Actual salary rate of employee involved, plus 16 percent of salary rate.	Applies	Does not apply	Does not apply.
(3) Clerical search	Actual salary rate of employee involved, plus 16 percent of salary rate.	Applies	Does not apply	Applies. No charge for first two hours of cumulative search time.
(4) Clerical review	Actual salary rate of employee involved, plus 16 percent of salary rate.	Applies	Does not apply	Does not apply.
(5) Programming services	$35 per hour	Applies	Does not apply	Applies.
(6) Computer run time (includes only mainframe search time not printing).	The direct cost of conducting the search.	Applies	Does not apply	Applies.
(7) Duplication costs	$0.18 per page	Applies	Applies. No charge for first 100 pages.	Applies. No charge for first 100 pages.
(8) Duplication costs—tape, CD ROM or diskette.	Actual cost	Applies	Applies	Applies.

* * * * *

(h) *Waiver or reduction of fees in the public interest.* If HUD determines that disclosure of the information you seek is in the public interest because it is likely to contribute significantly to public understanding of the operations or activities of the Federal Government, and that you are not seeking the information primarily for your own commercial interests, HUD may waive or reduce the fee.

(1) In order to qualify for a waiver or a reduction of fees, a requester must make the following demonstrations in the FOIA request:

(i) Disclosure of the requested information is in the public interest because it is likely to contribute significantly to public understanding of the operations or activities of the Federal Government.

(A) *The subject of the request pertains to the operations or activities of the Federal Government.* Requesters must be seeking documents and records that contain information regarding identifiable operations or activities of the Federal Government. The connection between the content of the records and Federal governmental operations or activities must be direct and clear.

(B) *The informative value of the information to be disclosed is consequential.* The disclosable portions of the requested records must be meaningfully informative about Federal Governmental operations or activities in order to be ''likely to contribute'' to an increased public understanding of those operations or activities. The disclosure of information that is already in the public domain, in either a duplicative or substantially identical form, would not be as likely to contribute to the public's understanding of Federal governmental operations or activities.

(C) *The disclosure is likely to contribute to an understanding of the subject by the public.* The disclosure must contribute to the understanding of a reasonably broad audience of persons interested in the subject, as opposed to the individual understanding of the requester, in order to provide a great benefit to the public at large. A requester's expertise in the subject area and ability and intention to effectively convey the information will be considered.

(D) *The contribution to public understanding is significant.* The public's understanding of the subject in question, as compared to the level of public understanding existing prior to the disclosure, must be enhanced by the disclosure to a substantial degree. HUD will not make value judgments about whether the information to be disclosed is worthy or important enough to be made public, but rather whether it would contribute substantially to public understanding of the operations or activities of the government.

(ii) Disclosure of the information is not primarily in the commercial interest of the requester.

(A) *The existence and magnitude of a commercial interest.* The requester must describe and explain any commercial interest that would be furthered by the requested disclosure, whether personally benefiting the requester or any person on whose behalf the requester may be acting. See the definition of a ''commercial use requester'' in paragraph (b)(1) of this section for further explanation.

(B) *Primary interest in disclosure.* A fee waiver or reduction in fees is justified where the requester has demonstrated that the public interest in disclosure is greater in magnitude than that of any identified commercial interest in disclosure. However, disclosure to data brokers or others who merely compile and market government information for direct economic return will not be presumed to primarily serve the public interest.

(2) Requests for waivers must address the elements listed in paragraph (h)(1) of this section, insofar as they apply to each request. HUD will exercise its discretion in considering the cost-effectiveness of its investment of administrative resources in deciding whether to grant waivers or reductions of fees, in consultation with appropriate offices as needed. Requests for the waiver or reduction of fees must be submitted with the request.

(3) When only some of the requested records satisfy the requirements for a waiver of fees, a waiver will be granted for only those records.

(4) When a fee waiver request is denied, HUD will do no further work on the request until it receives an assurance

of payment, or an appeal of the fee waiver adverse determination is filed and HUD has made a final appeal determination pursuant to § 15.112.

(i) *When do I pay the fee?* HUD will bill you when it responds to your request. You must pay within 31 calendar days. If the estimated fee is more than $250.00 or you have a history of failing to pay FOIA fees to HUD in a timely manner, HUD will ask you to remit the estimated amount and any past due charges before processing and sending you the records.

* * * * *

(k) *Contract services.* HUD will contract with private sector sources to locate, reproduce, and disseminate records in response to FOIA requests when that is the most efficient and least costly method. HUD will ensure that the ultimate cost to the requester is no greater than it would be if the agency itself had performed these tasks.

* * *

Dated: March 7, 2007.

Roy A. Bernardi,

Deputy Secretary.

[FR Doc. E7–4682 Filed 3–14–07; 8:45 am]

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At the end of each month, the Office of the Federal Register publishes separately a List of CFR Sections Affected (LSA), which lists parts and sections affected by documents published since the revision date of each title.

REMINDERS

The items in this list were editorially compiled as an aid to Federal Register users. Inclusion or exclusion from this list has no legal significance.

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This is a continuing list of public bills from the current session of Congress which have become Federal laws. It may be used in conjunction with "P L U S" (Public Laws Update Service) on 202–741–6043. This list is also available online at *http://www.archives.gov/federal-register/laws.html*.

The text of laws is not published in the **Federal Register** but may be ordered in "slip law" (individual pamphlet) form from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402 (phone, 202–512–1808). The text will also be made available on the Internet from GPO Access at *http://www.gpoaccess.gov/plaws/index.html*. Some laws may not yet be available.

H.R. 49/P.L. 110–7
To designate the facility of the United States Postal Service located at 1300 North Frontage Road West in Vail, Colorado, as the "Gerald R. Ford, Jr. Post Office Building". (Mar. 7, 2007; 121 Stat. 62)

H.R. 335/P.L. 110–8

To designate the facility of the United States Postal Service located at 152 North 5th Street in Laramie, Wyoming, as the "Gale W. McGee Post Office". (Mar. 7, 2007; 121 Stat. 63)

H.R. 433/P.L. 110–9

To designate the facility of the United States Postal Service located at 1700 Main Street in Little Rock, Arkansas, as the "Scipio A. Jones Post Office Building". (Mar. 7, 2007; 121 Stat. 64)

H.R. 514/P.L. 110–10

To designate the facility of the United States Postal Service located at 16150 Aviation Loop Drive in Brooksville, Florida, as the "Sergeant Lea Robert Mills Brooksville Aviation Branch Post Office". (Mar. 7, 2007; 121 Stat. 65)

H.R. 577/P.L. 110–11

To designate the facility of the United States Postal Service located at 3903 South Congress Avenue in Austin, Texas, as the "Sergeant Henry Ybarra III Post Office Building". (Mar. 7, 2007; 121 Stat. 66)

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