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DEPARTMENT OF AGRICULTURE

Federal Crop Insurance Corporation

7 CFR Parts 401 and 457

General Crop Insurance Regulations; Raisin Endorsement and Common Crop Insurance Regulations; Raisin Crop Insurance Provisions

AGENCY: Federal Crop Insurance Corporation, USDA.

ACTION: Final rule.

SUMMARY: The Federal Crop Insurance Corporation (FCIC) finalizes specific crop provisions for the insurance of raisins. The provisions will be used in conjunction with the Common Crop Insurance Policy Basic Provisions, which contain standard terms and conditions common to most crops. The intended effect of this action is to provide policy changes to better meet the needs of the insured, include the current raisin endorsement under the Common Crop Insurance Policy for ease of use and consistency of terms, and to restrict the effect of the current raisin endorsement to the 1996 and prior crop years.

EFFECTIVE DATE: March 14, 1997.

FOR FURTHER INFORMATION CONTACT: John Meyer, Insurance Management Specialist, Product Development Division, Policy Development and Standards Branch, Federal Crop Insurance Corporation, United States Department of Agriculture, 9435 Holmes Road, Kansas City, MO, 64131, telephone (816) 926–7730.

SUPPLEMENTARY INFORMATION:

Executive Order No. 12866

The Office of Management and Budget (OMB) has determined this rule to be exempt for the purposes of Executive Order No. 12866 and, therefore, this rule has not been reviewed by OMB.

Paperwork Reduction Act of 1995

Following publication of the proposed rule, 61 Federal Register, 55928, the public was afforded 60 days to submit written comments on information collection requirements previously approved by OMB under OMB control number 0563–0003 through September 30, 1998. No public comments were received.

Unfunded Mandates Reform Act of 1995

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. This rule contains no Federal mandates (under the regulatory provisions of title II of the UMRA) for State, local, and tribal governments or the private sector. Thus, this rule is not subject to the requirements of sections 202 and 205 of the UMRA.

Executive Order No. 12612

It has been determined under section 6(a) of Executive Order No. 12612, Federalism, that this rule does not have sufficient Federalism implications to warrant the preparation of a Federalism Assessment. The provisions contained in this rule will not have a substantial direct effect on states or their political subdivisions, or on the distribution of power and responsibilities among the various levels of government.

Regulatory Flexibility Act

This regulation will not have a significant impact on a substantial number of small entities. New provisions included in this rule will not impact small entities to a greater extent than large entities. Under the current regulations, all producers are required to complete an application and acreage report. If the crop is damaged or destroyed, insureds are required to give notice of loss and provide the necessary information to complete a claim for indemnity. This regulation does not alter those requirements. The amount of work required of the insurance companies delivering and servicing these policies will not increase significantly from the amount of work currently required. This rule does not have any greater or lesser impact on the producer. Therefore, this action is determined to be exempt from the provisions of the Regulatory Flexibility Act (5 U.S.C. 605), and no Regulatory Flexibility Analysis was prepared.

Federal Assistance Program

This program is listed in the Catalog of Federal Domestic Assistance under No. 10.450.

Executive Order No. 12372

This program is not subject to the provisions of Executive Order No. 12372, which require intergovernmental consultation with state and local officials. See the Notice related to 7 CFR part 3015, subpart V, published at 48 FR 29115, June 24, 1983.

Executive Order No. 12778

The Office of the General Counsel has determined that these regulations meet the applicable standards provided in sections 2(a) and 2(b)(2) of Executive Order No. 12778. The provisions of this rule will not have a retroactive effect prior to the effective date. The provisions of this rule will preempt state and local laws to the extent such state and local laws are inconsistent herewith. The administrative appeal provisions published at 7 CFR part 11 must be exhausted before any action for judicial review may be brought.

Environmental Evaluation

This action is not expected to have a significant impact on the quality of the human environment, health, and safety. Therefore, neither an Environmental Assessment nor an Environmental Impact Statement is needed.

National Performance Review

This regulatory action is being taken as part of the National Performance Review Initiative to eliminate unnecessary or duplicative regulations and improve those that remain in force.

Background

On Wednesday, October 30, 1996, FCIC published a proposed rule in the Federal Register at 61 FR 55928–55932 to add to the Common Crop Insurance Regulations (7 CFR part 457), a new section, 7 CFR 457.124, (Raisin Crop Insurance Provisions). The new provisions will replace and supersede the current provisions for insuring raisins found at 7 CFR section 401.142 and will be effective for the 1997 and succeeding crop years. Section 401.142

will also be amended to restrict its effect to the 1996 and prior crop years.

Following publication of the proposed rule, the public was afforded 30 days to submit written comments. A total of 20 comments were received from the crop insurance industry, Office of Inspector General (OIG), and FCIC Regional Service Offices (RSO). The comments received, and FCIC's responses, follow:

Comment: One comment from the insurance industry suggested definitions be added for ''insured tonnage,'' ''uninsured tonnage,'' and ''guaranteed tonnage.''

Response: Insured tonnage is throughly described and thereby ''defined'' in section 3 of the crop provisions. Several policy provisions are involved in determining tonnage that may not be insurable. Adding a definition to describe uninsured tonnage would be duplicative of these provisions. These provisions do not use the term ''guaranteed tonnage.'' Instead, a dollar guarantee is based on the number of insured tons. This allows damaged raisins to be valued and subtracted from the amount of insurance when determining the amount of an indemnity. No change has been made to the provisions.

Comment: One comment from the insurance industry questioned whether the definition of ''non-contiguous land'' should state ''that it is land ownership that does not touch at any point.''

Response: Land ownership is not a factor used to determine non-contiguous land. Rather, it is the boundaries of the land in which a producer has or will have an insurable interest in the crop. If the boundaries of such land do not touch, the land is considered to be non-contiguous. FCIC believes the provision is clearly stated. Therefore, no change will be made.

Comment: One comment from the insurance industry suggested changing the language in section 2(a) from ''may be divided'' to ''will be divided.''

Response: FCIC agrees with the comment and has amended the provisions accordingly.

Comments: Five comments, one from an RSO, one from OIG, and three from the crop insurance industry requested that ''optional'' be removed from the language in section 2(e). The comments indicated that this provision should apply to all units, both basic and optional.

Response: FCIC agrees with the comments and has amended the provision accordingly.

Comment: One comment from the insurance industry concerned the reference to ''your share'' in subsection 3(b). The commenter wanted to know if the reference applied to your share at time of loss, at the time the raisins were laid down for drying, or at some other time.

Response: Share is defined in the Basic Provisions. For the purpose of determining the premium amount, it is the share at the time insurance attaches. For the purpose of determining the amount of an indemnity, it is the lesser of the share at the time of loss or the share at the time insurance attaches.

Comment: One comment from the insurance industry concerned the determination of ''Insured tonnage for units damaged by rain'' in section 3(c)(2). The commenter suggested that adjusters should be allowed to determine which procedure to use to determine the total amount lost in the vineyard: tray count (which has been dropped), vine count, or both methods.

Response: Tray counts may not be reliable for determining production amounts. In some cases, it has been found that the number of trays cannot accurately be determined. However, the number of vines in a vineyard normally remains constant, and once production per vine is determined, vine count provides a more accurate method of determining total production in the vineyard. No change has been made to these provisions.

Comment: One comment from the insurance industry questioned how the following situation would be treated. An adjuster takes a sample to measure moisture content, finds that it exceeds 24.3% and releases the crop. The insured delays delivering the production and the moisture content decreases. The insured then delivers the raisins. What would happen in this situation and how could it be prevented?

Response: FCIC approved procedure prohibits an adjustor from releasing raisins before it is determined whether or not the crop can be reconditioned. However, the provision has been clarified to state that if any production is delivered, the moisture content will be determined at the time of delivery. Improper claim handling can be avoided with proper supervisory controls and by following established claims procedures as outlined in FCIC approved procedure.

Comment: Two comments, one from the insurance industry and one from OIG suggested adding language in section 3(c) indicating that an approved method be used to determine the number of tons lost in the vineyard in the event no production is removed from the vineyard. The Proposed Rule deleted the use of tray weights to establish insured tons when production is not removed from the vineyard and stated that when appraisal is required, the amount of raisin tonnage lost will be determined in sample areas. The commenters stated that the policy, as drafted, does not address these situations. Also, when these situations occur, the comparison to other acreage from which raisins were removed is not possible. Loss adjustment procedures should contain a method for handling these situations and state or define how the production will be determined from such sample areas or give a sampling methodology as cited in the ''Background'' section. Determinations for these situations would then be used as necessary in valuing damaged raisins under the provisions of section 13(f).

Response: FCIC agrees with the comment and has added a provision to state that when no raisins have been removed from the vineyard, an appraisal will be used to determine the insured tonnage. FCIC approved procedures provide the methods to be used to determine tonnage lost in the vineyard when no raisins are removed.

Comment: Six comments, one from OIG, one from an RSO, and four from the crop insurance industry suggested the following language be added in section 6(b) to address situations in which the insured either adds or deletes acreage after providing the required report of intentions at sales closing date: ''Acreage on which you intend to produce raisins may be added to your location report until the time you first place raisins from the additional acreage on trays for drying and it is agreed to by us. Failure to report any insurable acreage will result in under-reporting penalties being applied in accordance with the provisions contained in section 6 (Report of Acreage) of the Basic Provisions (457.8). If you elect not to produce raisins on any acreage included on your location report, you must notify us in writing on or before September 21 and provide any records we may require to verify that raisins were not produced on that acreage.'' The comments indicated this language is necessary to address vulnerabilities associated with reporting tonnage, and that the current language is vague and will result in unnecessary exposure.

Response: FCIC agrees with the comments and has amended the provisions to clarify the conditions under which additional acreage may be added to the acreage report.

Comments: Two comments from the insurance industry indicated that statements in item 6 of the summary of changes section in the preamble and in section 6(a) of the provisions appeared to be in conflict. The background summary section refers to ''reporting raisin acreage prior to the time insurance attaches'' whereas section 6(a) requires this report to be submitted on or before the sales closing date.

Response: FCIC agrees with the comments. The background section should have stated that raisin acreage must be reported on or before the sales closing date.

Comment: One comment from the insurance industry favored having the insured report the acreage and location more timely but questioned: (1) Why the guarantee can not be determined at this time; (2) would a growing season inspection be required if an insured leases ground after insurance attaches; and (3) what happens when there is a forecast of rain and the insured notifies the company that additional acreage has been leased?

Response: The amount of insurance cannot be calculated until the insured tonnage can be determined. Insured tonnage is not known until after the crop is laid down to dry and the production is delivered or determined in the event of damage. Additional acreage cannot be added after the raisins have been laid down on the additional acreage; so no new acreage can be added after insurance has attached. If raisins are leased after they have been laid down, such raisins are only insurable if the lessor had insurance and properly executed a transfer of coverage and right to indemnity. Further additional acreage may only be added to the acreage report after the sales closing date if the insurer agrees. In the event rain is forecast, the insurance provider may deny coverage on the acreage.

Comment: One comment from the insurance industry questioned why the term ''Location and Unit Report'' was used for what appears to be a preliminary acreage report. The commenter stated that, if there were significant differences between the two terms such that a different form is required, the industry would like to help develop such a form before the Raisin Crop Insurance Provisions are published as a Final Rule.

Response: ''Location and unit report'' was thought to be a more descriptive term than ''acreage report.'' However, after additional consideration, FCIC believes that the current acreage report form may be used to obtain all information required by these Crop Provisions. Therefore, the term ''Location and unit report'' has been replaced with ''acreage report.''

Comments: Six comments, one from OIG, one from an RSO, and four from the crop insurance industry suggested that section 8(b) which states ''For the purpose of determining the amount of indemnity, your share will not exceed the lower of your share at either the time the raisins are first placed on trays for drying or are removed from the vineyards.'' be revised to read ''For the purpose of determining the amount of indemnity, your share will not exceed your share at the time the insurance attaches.'' The comment also stated that the insurance period for raisins lasts only two or three weeks and changes in share are uncommon once the crop is on trays. Also, it was stated that if this section is not revised, that consideration be given to using ''lesser of'' in lieu of ''lower of''.

Response: FCIC understands that it is uncommon for the share to change within the insurance period. However, in those cases where it does change, the insurance provider should not pay for a share in excess of the insured's share at the time of loss. FCIC has revised this provision to indicate that the share will not exceed the lesser of the share at the time insurance attaches or at the time of loss. For clarification, this provision was moved to section 13(c) (Settlement of Claim).

Comments: Seven comments, one from OIG, one from an RSO, and five from the crop insurance industry, suggested the following be added to the last sentence of section 11(a) ''or determine the number of tons meeting RAC standards that could be obtained if the production were reconditioned.'' It was indicated that this language is necessary to be equitable to producers who intend to sell rain-damaged raisins through alternative market outlets.

Response: FCIC agrees with the comments and has amended the provision to indicate that the insurance provider may determine the tons meeting RAC standards that could be obtained if the raisins were reconditioned. Language has also been added to clarify the circumstances under which this action can be taken.

Comment: One comment questioned whether all items of sub-section 11(c)(1)(2)&(3) must occur to get a reconditioning payment, or, are different combinations possible? If all three are required, the ''or'' at the end of (2) should be changed to ''and'', or delete it and the ''and'' at the end of (1). If all three occurrences are not required, which combinations are acceptable?

Response: Two possible combinations are acceptable. Either 11(c) (1) and (2) are required, or 11(c) (1) and (3).

Comment: One comment from the insurance industry expressed concern that, since insured's with catastrophic risk protection (CAT) insurance are not eligible for a reconditioning payment, they may ''drag their feet'' in hopes of collecting a regular production loss. Is the reconditioning requirement language in sub-section 11(a) strong enough to discourage or prevent possible abuse?

Response: FCIC believes that policy provisions dealing with poor farming practices and the valuation of damaged production if the insured fails to recondition the raisins should prevent cases in which insureds may try to inflate losses.

Comments: Five comments, one from an RSO, and four from the insurance industry suggested replacing the term ''micro-contamination'' in section 11(c)(2) with ''other rain-caused contamination determined by micro-analysis * * *'' The comment stated this language would be more accurate since insects infest rain damaged raisins, and micro-analysis is used to identify insects and insect parts that will not be removed during normal processing.

Response: FCIC agrees with the comments and has amended the provision accordingly.

Comment: One comment concerned item 8 in the background section of the preamble (substantive change summary). This provision states that ''raisins discarded or lost from trays as part of normal handling will not be considered production to count.'' The comment stated this would not be a problem until it rains and the handlers throw off moldy raisins and what remains on the trays. Question is, would this production not be used to determine the guarantee and production to count?

Response: Normal field handling does not include raisins which are discarded after a loss. If such raisins are discarded, they should not be included in the insured tonnage or the value of the damaged production.

Comments: Two comments from the crop insurance industry suggested combining the provisions contained in section 14(e) with the provisions in section 14(a).

Response: The provisions are clearly stated and have not been combined.

Comments: Two comments received from the insurance industry suggested the provision in section 14(d) stating ''that written agreements are valid for only one year'' be removed. Terms of the agreement should be stated in the agreement to fit the particular situation for the policy, or if no substantive changes occur from one year to the next, allow the written agreement to be continuous.

Response: Written agreements are intended to change policy terms or permit insurance in unusual situations where such changes will not increase risk. If such practices continue year to year, they should be incorporated into the policy or Special Provisions. It is important to keep non-uniform exceptions to the minimum to ensure that the insured is well aware of the specific terms of the policy. Therefore, no change will be made.

Good cause is shown to make this rule effective upon publication in the Federal Register. This rule improves the raisin crop insurance coverage and brings it under the Common Crop Insurance Policy Basic Provisions for consistency among policies. The contract change date required for new policies is April 30, 1997. It is therefore imperative that these provisions be made final before that date so that the reinsured companies and insureds may have sufficient time to implement the new provisions.

Therefore, public interest requires the agency to act immediately to make these provisions available for the 1997 crop year.

List of Subjects in 7 CFR Parts 401 and 457

Crop insurance, Raisin endorsement.

Final Rule

Accordingly, the Federal Crop Insurance Corporation hereby amends 7 CFR parts 401 and 457 effective for the 1997 and succeeding crop years, as follows:

PART 401—GENERAL CROP INSURANCE REGULATIONS—REGULATIONS FOR THE 1988 AND SUBSEQUENT CONTRACT YEARS

1. The authority citation for 7 CFR part 401 continues to read as follows:

Authority: 7 U.S.C. 1506(l), 1506(p).

§ 401.142 [Revised]

2. The introductory text of § 401.142 is revised to read as follows:

The provisions of the Raisin Endorsement for the 1990 through 1996 crop years are as follows:

* * * * *

PART 457—COMMON CROP INSURANCE REGULATIONS; REGULATIONS FOR THE 1994 AND SUBSEQUENT CONTRACT YEARS

3. The authority citation for 7 CFR part 457 continues to read as follows:

Authority: 7 U.S.C. 1506(l), 1506(p).

4. Section 457.124 is added to read as follows:

§ 457.124 Raisin crop insurance provisions.

The Raisin Crop Insurance Provisions for the 1997 and succeeding crop years are as follows:

FCIC Policies

Department of Agriculture

Federal Crop Insurance Corporation

Reinsured Policies

(Appropriate title for insurance provider)

Both FCIC and Reinsured Policies:

Raisin Crop Provisions

If a conflict exists among the Basic Provisions (§ 457.8), these Crop Provisions, and the Special Provisions; the Special Provisions will control these Crop Provisions and the Basic Provisions; and these Crop Provisions will control the Basic Provisions.

1. Definitions.

Crop year—In lieu of the definition of ‘‘Crop year’’ contained in section 1 of the Basic Provisions (§ 457.8), the calendar year in which the raisins are placed on trays for drying.

Days—Calendar days.

Delivered ton—A ton of raisins delivered to a packer, processor, buyer or a reconditioner, before any adjustment for U. S. Grade B and better maturity standards, and after adjustments for moisture over 16 percent and substandard raisins over 5 percent.

Non-contiguous land—Any two or more tracts of land whose boundaries do not touch at any point, except that land separated only by a public or private right-of-way, waterway, or an irrigation canal will be considered as contiguous.

RAC—The Raisin Administrative Committee, which operates under an order of the United States Department of Agriculture (USDA).

Raisins—The sun-dried fruit of varieties of grapes designated insurable by the Actuarial Table. These grapes will be considered raisins for the purpose of this policy when laid on trays in the vineyard to dry.

Substandard—Raisins that fail to meet the requirements of U.S. Grade C, or layer (cluster) raisins with seeds that fail to meet the requirements of U.S. Grade B.

Reference maximum dollar amount—The value per ton established by FCIC and shown in the Actuarial Table.

Table grapes—Grapes grown for commercial sale as fresh fruit on acreage where appropriate cultural practices were followed.

Ton—Two thousand (2,000) pounds avoirdupois.

Tonnage report—A report used to annually report, by unit, all the tons of raisins produced in the county in which you have a share.

Written agreement—A written document that alters designated terms of this policy in accordance with section 14.

2. Unit Division.

(a) In addition to the requirements of a unit as defined in section 1 (Definitions) of the Basic Provisions (§ 457.8), a basic unit will consist of each grape variety you insure.

(b) Unless limited by the Special Provisions, a basic unit may be divided into optional units if, for each optional unit you meet all the conditions of this section or if a written agreement to such division exists.

(c) Basic units may not be divided into optional units on any basis including, but not limited to, production practice, type, and variety, other than as described in this section.

(d) If you do not comply fully with these provisions, we will combine all optional units that are not in compliance with these provisions into the basic unit from which they were formed. We will combine the optional units at any time we discover that you have failed to comply with these provisions. If failure to comply with these provisions is determined to be inadvertent, and the optional units are combined into a basic unit, that portion of the additional premium paid for the optional units that have been combined will be refunded to you for the units combined.

(e) All units you selected for the crop year must be identified on the acreage report for that crop year.

(f) The following requirements must be met to qualify for separate optional units.

(1) You must have records of marketed production or measurement of stored production from each optional unit maintained in such a manner that permits us to verify the production from each optional unit, or the production from each unit must be kept separate until loss adjustment is completed by us; and

(2) Separate optional units must be located on non-contiguous land.

3. Amounts of Insurance and Production Reporting .

In addition to the requirements of section 3 (Insurance Guarantees, Coverage Levels, and Prices for Determining Indemnities) of the Basic Provisions (§ 457.8):

(a) You may select only one coverage level percentage for all the raisins in the county insured under this policy.

(b) The amount of insurance for the unit will be determined by multiplying the insured tonnage by the reference maximum dollar amount, by the coverage level percentage you elect, and by your share.

(c) Insured tonnage is determined as follows:

(1) For units not damaged by rain—The delivered tons; or

(2) For units damaged by rain—By adding the delivered tons to any verified loss of production due to rain damage. When production from a portion of the acreage within a unit is removed from the vineyard and production from the remaining acreage is lost in the vineyard, the amount of production lost in the vineyard will be determined based on the number of tons of raisins produced on the acreage from which production was removed. When no production has been removed from the vineyard, the amount of production lost in the vineyard will be determined based on an appraisal.

(3) Insured tonnage will be adjusted as follows:

(i) The insured tonnage will be reduced 0.12 percent for each 0.10 percent of moisture in excess of 16.0 percent. For example, 10.0 tons of raisins containing 18.0 percent moisture will be reduced to 9.760 tons of raisins;

(ii) Insured tonnage used for dry edible fruit will be reduced by 0.10 percent for each 0.10 percent of substandard raisins in excess of 5.0 percent; and

(iii) When raisins contain moisture in excess of 24.3 percent at the time of delivery and are released for a use other than dry edible fruit (e.g. distillery material), they will be considered to contain 24.3 percent moisture.

(4) If any raisins are delivered, the moisture content will be determined at the time of delivery.

(d) Section 3(c) of the Basic Provisions is not applicable to this crop.

4. Contract Changes.

In accordance with section 4 (Contract Changes) of the Basic Provisions (§ 457.8), the contract change date is April 30 preceding the cancellation date.

5. Cancellation and Termination Dates.

In accordance with section 2 (Life of Policy, Cancellation and Termination) of the Basic Provisions (§ 457.8), the cancellation and termination dates are July 31.

6. Acreage Report and Tonnage Report.

In lieu of the provisions contained in section 6 of the Basic Provisions (§ 457.8):

(a) You must report by unit, and on our form, the acreage on which you intend to produce raisins for the crop year. This acreage report must be submitted to us on or before the sales closing date, and contain the following information:

(1) All acreage of the crop (insurable and not insurable) in which you will have a share;

(2) Your anticipated share at the time coverage will begin;

(3) The variety; and

(4) The location of each vineyard.

(b) Acreage of the crop acquired after the acreage was reported, may be included on the acreage report if we agree to accept the additional acreage. Such additional acreage will not be added to the acreage report after you first place raisins from the additional acreage on trays for drying. Failure to report any acreage in which you have a share will result in denial of liability. If you elect not to produce raisins on any part of the acreage included on your acreage report, you must notify us in writing on or before September 21, and provide any records we may require to verify that raisins were not produced on that acreage.

(c) If you fail to file an acreage report in a timely manner, or if the information reported is incorrect, we may deny liability on any unit.

(d) In addition to the acreage report, you must annually submit a tonnage report, on our form, which includes by unit the number of delivered tons of raisins, and, if damage has occurred, the amount of any tonnage we determined was lost due to rain damage in the vineyard for each unit designated in the acreage report.

(e) The tonnage report must be submitted to us as soon as the information is available, but not later than March 1 of the year following the crop year. Indemnities may be determined on the basis of information you submitted on this report. If you do not submit this report by the reporting date, we may, at our option, either determine the insured tonnage and share by unit or we may deny liability on any unit. This report may be revised only upon our approval. Errors in reporting units may be corrected by us at any time we discover the error.

7. Annual Premium.

In lieu of the premium computation method contained in section 7 (Annual Premium) of the Basic Provisions (§ 457.8), the annual premium amount is determined by multiplying the amount of insurance for the unit at the time insurance attaches by the premium rate and then multiplying that result by any applicable premium adjustment factors that may apply.

8. Insured Crop.

(a) In accordance with section 8 (Insured Crop) of the Basic Provisions (§ 457.8), the crop insured will be all the raisins in the county of grape varieties for which a premium rate is provided by the Actuarial Table and in which you have a share.

(b) In addition to the raisins not insurable under section 8 (Insured Crop) of the Basic Provisions (§ 457.8), we do not insure any raisins:

(1) Laid on trays after September 8 in vineyards with north-south rows in Merced or Stanislaus Counties, or after September 20 in all other counties;

(2) From table grape strippings; or

(3) From vines that received manual, mechanical, or chemical treatment to produce table grape sizing.

9. Insurance Period.

In lieu of the provisions of section 11 (Insurance Period) of the Basic Provisions (§ 457.8), insurance attaches on each unit at the time the raisins are placed on trays for drying and ends the earlier of:

(a) October 20;

(b) The date the raisins are removed from the trays;

(c) The date the raisins are removed from the vineyard;

(d) Total destruction of all raisins on a unit;

(e) Final adjustment of a loss on a unit; or

(f) Abandonment of the raisins.

10. Causes of Loss.

(a) In accordance with the provisions of section 12 (Causes of Loss) of the Basic Provisions (§ 457.8), insurance is provided only against unavoidable loss of production resulting from rain that occurs during the insurance period and while the raisins are on trays or in rolls in the vineyard for drying.

(b) In addition to the causes of loss excluded in section 12 (Causes of Loss) of the Basic Provisions (§ 457.8), we will not insure against damage or loss of production due to inability to market the raisins for any reason other than actual physical damage from an insurable cause specified in this section. For example, we will not pay you an indemnity if you are unable to market due to quarantine, boycott, or refusal of a person to accept production.

11. Reconditioning Requirements and Payment.

(a) We may require you to recondition a representative sample of not more than 10 tons of damaged raisins to determine if they meet standards established by the RAC once reconditioned. If such standards are met, we may require you to recondition all the damaged production. If we determine that it is possible to recondition any damaged production and, if you do not do so, we will value the damaged production at the reference maximum dollar amount, except if your damaged production undergoes a USDA inspection and is stored by your packer with other producer's production to be reconditioned at a later date. If we agree, in writing, that it is not practical to recondition the damaged production, we will determine the number of tons meeting RAC standards that could be obtained if the production were reconditioned.

(b) If the representative sample of raisins that we require you to recondition does not meet RAC standards for marketable raisins after reconditioning, the reconditioning payment will be the actual cost you incur to recondition the sample, not to exceed an amount that is reasonable and customary for such reconditioning, regardless of the coverage level selected.

(c) A reconditioning payment, based on the actual (unadjusted) weight of the raisins, will be made if:

(1) Insured raisin production:

(i) Is damaged by rain within the insurance period;

(ii) Is reconditioned by washing with water and then drying;

(iii) Is insured at a coverage level greater than that applicable to the catastrophic risk protection plan of insurance; and either

(2) The damaged production undergoes an inspection by USDA and is found to contain mold, embedded sand, or other rain-caused contamination determined by micro-analysis in excess of standards established by the RAC, or is found to contain moisture in excess of 18 percent; or

(3) We give you consent to recondition the damaged production.

(d) Your request for consent to any wash-and-dry reconditioning must identify the acreage on which the production to be reconditioned was damaged in order to be eligible for a reconditioning payment.

(e) The reconditioning payment for raisins that meet RAC standards for marketable raisins after reconditioning will be the lesser of your actual cost for reconditioning or the amount determined by:

(1) Multiplying the greater of $125.00 or the reconditioning dollar amount per ton contained in the Special Provisions by your coverage level;

(2) Multiplying the result of section 11(e)(1) by the actual number of tons of raisins (unadjusted weight) that are wash-and-dry reconditioned; and

(3) Multiplying the result of section 11(e)(2) by your share.

(f) Only one reconditioning payment will be made for any lot of raisins damaged during the crop year. Multiple reconditioning payments for the same production will not be made.

12. Duties In The Event of Damage or Loss.

(a) In addition to the requirements of section 14 (Duties in the Event of Damage or Loss) of the Basic Provisions (§ 457.8), the following will apply:

(1) If you intend to claim an indemnity on any unit, you must give us notice within 72 hours of the time the rain fell on the raisins. We may reject any claim for indemnity if such notice is later. You must provide us the following information when you give us this notice:

(i) The grape variety;

(ii) The location of the vineyard and number of acres; and

(iii) The number of vines from which the raisins were harvested.

(2) We will not pay any indemnity unless you:

(i) Authorize us in writing to obtain all relevant records from any raisin packer, raisin reconditioner, the RAC, or any other person who may have such records. If you fail to meet the requirements of this subsection, all insured production will be considered undamaged and valued at the reference maximum dollar value.

(ii) Upon our request, provide us with records of previous years'' production and acreage. This information may be used to establish the amount of insured tonnage when insurable damage results in discarded production.

(b) In lieu of the provisions in section 14 (Duties in the Event of Damage or Loss) of the Basic Provisions (§ 457.8) that require you to submit a claim for indemnity not later than 60 days after the end of the insurance period, any claim for indemnity must be submitted to us not later than March 31 following the date for the end of the insurance period.

13. Settlement of Claim.

(a) We will determine your loss on a unit basis. In the event you are unable to provide separate acceptable production records:

(1) For any optional unit, we will combine all optional units for which such production records were not provided; or

(2) For any basic unit, we will allocate any commingled production to such units in proportion to our liability on the acreage from which raisins were removed for each unit.

(b) In the event of loss or damage covered by this policy, we will settle your claim by:

(1) Multiplying the insured tonnage of raisins by the reference maximum dollar amount and your coverage level percentage;

(2) Subtracting from the total in section 13(b)(1) the total value of all insured damaged and undamaged raisins; and

(3) Multiplying the result of section 13(b)(2) by your share.

(c) For the purpose of determining the amount of indemnity, your share will not exceed the lesser of your share at the time insurance attaches or at the time of loss.

(d) Undamaged raisins or raisins damaged solely by uninsured causes will be valued at the reference maximum dollar amount.

(e) Raisins damaged partially by rain and partially by uninsured causes will be valued at the highest prices obtainable, adjusted for any reduction in value due to uninsured causes.

(f) Raisins that are damaged by rain, but that are reconditioned and meet RAC standards for raisins, will be valued at the reference maximum dollar amount.

(g) The value to count for any raisins produced on the unit that are damaged by rain and not removed from the vineyard will be the larger of the appraised salvage value or $35.00 per ton, except that any raisins that are damaged and discarded from trays or are lost from trays scattered in the vineyard as part of normal handling will not be considered to have any value. You must box and deliver any raisins that can be removed from the vineyard.

(h) At our sole option, we may acquire all the rights and title to your share of any raisins damaged by rain. In such event, the raisins will be valued at zero in determining the amount of loss and we will have the right of ingress and egress to the extent necessary to take possession, care for, and remove such raisins.

(i) Raisins destroyed, put to another use without our consent, or abandoned will be valued at the reference maximum dollar amount.

14. Written Agreements.

Designated terms of this policy may be altered by written agreement in accordance with the following:

(a) You must apply in writing for each written agreement no later than the sales closing date, except as provided in 14(e);

(b) The application for a written agreement must contain all variable terms of the contract between you and us that will be in effect if the written agreement is not approved;

(c) If approved, the written agreement will include all variable terms of the contract, including, but not limited to, crop type or variety, the amount of insurance per ton, and premium rate;

(d) Each written agreement will only be valid for one year (If the written agreement is not specifically renewed the following year, insurance coverage for subsequent crop years will be in accordance with the printed policy); and

(e) An application for a written agreement submitted after the sales closing date may be approved if, after a physical inspection of the acreage, it is determined that no loss has occurred and the crop is insurable in accordance with the policy and written agreement provisions.

Signed in Washington, DC, on March 6, 1997.

Kenneth D. Ackerman,

Manager, Federal Crop Insurance Corporation.

[FR Doc. 97–6520 Filed 3–13–97; 8:45 am]

BILLING CODE 3410–08–P

FEDERAL HOUSING FINANCE BOARD

12 CFR Part 935

[No. 97–18]

Advances to Nonmembers

AGENCY: Federal Housing Finance Board.

ACTION: Final rule.

SUMMARY: The Board of Directors of the Federal Housing Finance Board (Finance Board) is amending its regulation on Federal Home Loan Bank (FHLBank) advances to nonmembers. The rule establishes uniform eligibility requirements and review criteria for determining whether an entity may be certified as a nonmember mortgagee eligible to receive FHLBank advances and devolves responsibility for making that determination from the Finance Board to the FHLBanks. The Finance Board also is revising the definition of the term ''state housing finance agency'' (SHFA) to include all tribally designated housing entities (TDHEs). The rule is part of the Finance Board's continuing effort to devolve management and governance responsibilities to the FHLBanks and is consistent with the goals of the National Homeownership Strategy and the Regulatory Reinvention Initiative of the National Performance Review.

EFFECTIVE DATE: The final rule will become effective April 14, 1997.

FOR FURTHER INFORMATION CONTACT: Christine M. Freidel, Associate Director, Financial Management Division, Office of Policy, 202/408–2976; Laura K. St. Claire, Financial Analyst, Financial Management Division, Office of Policy, 202/408–2811; or, Janice A. Kaye, Attorney-Advisor, Office of General Counsel, 202/408–2505, Federal Housing Finance Board, 1777 F Street, N.W., Washington, D.C. 20006.

SUPPLEMENTARY INFORMATION:

I. Statutory and Regulatory Background

Section 10b of the Federal Home Loan Bank Act (Bank Act) establishes the requirements for access by nonmember mortgagees to FHLBank advances. *See* 12 U.S.C. 1430b. In order to be certified as a nonmember mortgagee, an entity must: (1) Be approved by the Department of Housing and Urban Development (HUD) as a ''mortgagee'' under title II of the National Housing Act; (2) be chartered under law and have succession; (3) be subject to the inspection and supervision of a governmental agency; and (4) lend its own funds as its principal activity in the mortgage field. *Id.* 1430b(a).

Under section 10b(a) of the Bank Act, advances to nonmember mortgagees are not subject to the general collateral requirements of section 10(a) of the Bank Act. *Id.* Instead, a FHLBank may make advances to nonmember mortgagees only upon the security of mortgages insured by the Federal Housing Administration (FHA) of HUD under title II of the National Housing Act. *Id.* The amount of any advance may not exceed 90 percent of the unpaid principal of the collateral pledged as security for the advance. *Id.*

The Bank Act imposes less restrictive collateral requirements on certain advances to nonmember mortgagees that are SHFAs. *Id.* 1430b(b). Under section 10b(b) of the Bank Act, advances to SHFA nonmember mortgagees that facilitate mortgage lending to low- or moderate-income individuals and families (meeting the income requirements in section 142(d) or 143(f) of the Internal Revenue Code, generally up to 115 percent of the area median income) need not be secured by FHA-insured mortgage loans if the advances otherwise meet the requirements of section 10(a) of the Bank Act and any real estate collateral pledged to secure the advances is comprised of single- or multi-family residential mortgages. *Id.* 1430b(b), 1430(a); 26 U.S.C. 142(d), 143(f). Under section 10(a), the four categories of collateral are eligible to secure advances to members are: (1) Fully disbursed whole first mortgage loans on improved residential real property that are not more than 90 days delinquent or securities representing a whole interest in such mortgages; (2) securities issued, insured, or guaranteed by the United States government or any agency thereof; (3) deposits of a FHLBank; and (4) other real estate related collateral if such collateral has a readily ascertainable value and the FHLBank can perfect its interest therein.[1]

In October 1996, the Finance Board published for comment a proposed rule that would transfer the authority to certify an entity as a nonmember mortgagee eligible to receive FHLBank advances from the Finance Board to the FHLBanks subject to uniform review criteria for determining compliance with statutory and regulatory eligibility requirements. *See* 61 FR 52727 (Oct. 8, 1996). The 60-day public comment period closed on December 9, 1996. *See id.* The Finance Board received a total of 12 comments in response to the proposed rule, 6 from FHLBanks, 4 from trade associations, and 1 each from a certified SHFA nonmember mortgagee and a federal agency. All of the commenters generally supported the Finance Board's proposal. Specific comments are discussed in Part II of the SUPPLEMENTARY INFORMATION.

II. Analysis of Public Comments and the Final Rule

A. Definitions

The final rule amends the definition of the term ''state housing finance agency'' that appears in § 935.1 to include TDHEs[2] established under both tribal and state law as SHFAs. This will permit every TDHE nonmember mortgagee that makes mortgage loans to low- and moderate-income members of the Indian community to take advantage of the more flexible collateral requirements for securing advances to SHFA nonmember mortgagees. *See supra* part I; 12 U.S.C. 1430b(b). Each of the eight commenters addressing this issue expressly supported inclusion of all TDHEs in the definition and it is being adopted as proposed. A trade association commenter suggested that entities other than SHFAs should not be

[1] *See* 12 U.S.C. 1430(a)(1)–(4). Other acceptable real estate related collateral includes, but is not limited to: privately issued mortgage-backed securities other than those eligible under category 1; second mortgage loans, including home equity loans; commercial real estate loans; and mortgage loan participations. *See* 12 CFR 935.9(a)(4)(ii). The aggregate amount of outstanding advances secured by such collateral may not exceed 30 percent of a FHLBank member's GAAP capital. *See* 12 U.S.C. 1430(a)(4); 12 CFR 935.9(a)(4)(iii).

[2] Congress enacted the Native American Housing Assistance and Self Determination Act of 1996 in October 1996. *See* Pub. L. 104–330, 101 Stat. 4016 (Oct. 26, 1996). The Act authorizes Indian tribes to establish TDHEs to run their housing programs. *See id.* sec. 102(c)(4)(K), 110 Stat. 4025. TDHEs include all existing Indian Housing Authorities as well as other entities created by Indian tribes to provide assistance for affordable housing for tribal members. *See id.* sec. 4(21), 110 Stat 4021.

eligible for certification as nonmember mortgagees. However, because section 10b of the Bank Act clearly sets forth two classes of nonmember mortgagees, one composed of SHFAs and one composed of non-SHFAs, *see* 12 U.S.C. 1430b, the suggestion would be contrary to the Bank Act and the Finance Board has not adopted it in the final rule.

The Finance Board received two responses to a specific request for comments regarding the inclusion of other groups in the definition of SHFA. One commenter noted its belief that the definition as written is sufficiently broad to cover the Department of Hawaiian Homelands, a Hawaii state agency with responsibility for administering the Hawaiian Homes Commission Act on behalf of Native Hawaiians. Without additional detailed information, the Finance Board cannot determine whether a particular entity meets the requirements of the SHFA definition. Under the final rule, the Banks would make this determination at the time an entity applies for certification as a nonmember mortgagee. The other commenter suggested including certain nonprofit community development financial institutions (CDFIs) in the SHFA definition. The Finance Board based its definition of SHFA on the meaning given that term for purposes of other provisions in the Bank Act. As defined elsewhere in the Bank Act, the term SHFA requires the entity to be a government instrumentality. *See id.* 1441a(c)(9)(P), 1441a–1(1). Accordingly, the Finance Board's definition of SHFA requires an entity to be a government instrumentality. Since nonprofit CDFIs are not government instrumentalities, they cannot be certified as SHFA nonmember mortgagees. However, nonprofit CDFIs that meet the eligibility requirements currently may be certified as nonmember mortgagees.

B. Advances to the Savings Association Insurance Fund

The Finance Board received no comments on § 935.20 and is adopting the section as proposed. Section 935.20, which implements section 31(k) of the Bank Act, *see id.* 1431(k), provides that an FHLBank may make advances to the Federal Deposit Insurance Corporation for the use of the Savings Association Insurance Fund under certain circumstances and subject to specific conditions.

C. Scope

Section 935.21 provides that advances to nonmember mortgagees generally are subject to subpart A of part 935, which governs advances to FHLBank members. *See* 12 CFR 935.1–935.19. A trade association commenter suggested that the final rule prevent the FHLBanks from applying requirements, terms, and conditions to nonmember mortgagees that are not also applied to members. The Finance Board believes that this provision should achieve that result. One exception to this general requirement relates to the non-qualified thrift lender (non-QTL) provisions of the Finance Board's advances regulation. *See id.* § 935.13. Since the statutory limit on aggregate FHLBank lending applies only to advances to non-QTL *members, see* 12 U.S.C. 1430(e)(2) (emphasis added), and nonmember mortgagees are not FHLBank members, advances to nonmember mortgagees need not be included in the aggregate limit on advances to non-QTLs. A trade association commenter strongly supported this provision as offering assurance that nonmember mortgagees would not limit non-QTL members' access to advances.

D. Nonmember Mortgagee Eligibility Requirements

1. Eligibility Criteria

Section 935.22(a) authorizes the FHLBanks to make advances to an entity that is not a member of the FHLBank if the FHLBank certifies the entity as a nonmember mortgagee. Section 935.22(b) sets forth the eligibility requirements an entity must meet in order to be certified as a nonmember mortgagee. In addition to the four statutory eligibility criteria discussed in part 1 of the **SUPPLEMENTARY INFORMATION**, to ensure the safety and soundness of the FHLBanks, the Finance Board has incorporated a financial condition criterion that requires an applicant's financial condition to be such that an FHLBank may safely lend to it. This is the same financial condition criterion that applies currently to applicants for membership in an FHLBank. *See id.* 1424(a)(2)(B); 12 CFR 933.6(a)(4). The Finance Board received no comments on these provisions and is adopting them without change from the proposal.

2. Review Criteria

Section 935.22(c) establishes uniform review criteria the FHLBanks must apply to determine whether an applicant meets the eligibility requirements for certification as a nonmember mortgagee. If an applicant fulfills each criterion to the satisfaction of the FHLBank to which it has applied, it will be deemed to meet the eligibility requirements. Conversely, failure to fulfill each criterion to the satisfaction of the FHLBank will render the applicant ineligible, subject to appeal to the Finance Board, to be certified as a nonmember mortgagee.

Under § 935.22(c)(1), an applicant is deemed to meet the requirement that it be approved under title II of the National Housing Act if it submits a current HUD Yearly Verification Report or other documentation issued by HUD stating that the applicant is an approved FHA mortgagee.

Under § 935.22(c)(2), an applicant is deemed to meet the requirement that it be a chartered institution having succession if it provides evidence satisfactory to the FHLBank that it is a government agency, or is chartered under state, federal, local, tribal, or Alaska Native village law as a corporation or other entity that has rights, characteristics, and powers similar to those granted a corporation. An FHLBank commenter noted that satisfactory evidence, such as statutory and regulatory materials, is usually readily available to the FHLBanks, and therefore suggested that the final rule require an applicant to provide only a citation to, rather than copies of, appropriate documents. For that reason, and to reduce the paperwork burden imposed on nonmember mortgagee applicants, the Finance Board has deleted the requirement that an applicant provide ''documentary'' evidence in the final rule. Of course, if an FHLBank should require copies of statutes, regulations, or other relevant documents, it has authority to require their submission under § 935.23(c)(1). *See infra.* In any case, an FHLBank must include copies of all documents upon which it relied in making its certification decision as part of the certification file required under § 935.23(c)(3). *See infra.*

Under § 935.22(c)(3), an applicant is deemed to meet the requirement that it be subject to the inspection and supervision of some governmental agency if it provides evidence satisfactory to the FHLBank that, pursuant to statute or regulation, it is subject to the inspection and supervision of a federal, state, local, tribal, or Alaska Native village governmental agency. Satisfactory evidence generally consists of a citation to, or copies of, relevant statutory and regulatory materials. For the same reasons as discussed above for § 935.22(c)(2), the Finance Board has deleted the requirement that an applicant provide ''documentary'' evidence in the final rule.

In order to establish an appropriate standard for the FHLBanks to determine whether an applicant meets the inspection and supervision requirement, the Finance Board recast the illustrative examples in the proposal as standards for meeting the inspection and supervision requirements. The rule provides that an applicant will be deemed to meet the subject to inspection by a governmental agency requirement if there is a statutory or regulatory requirement that the applicant's books and records be audited or examined periodically by a governmental agency or an external auditor. This audit factor was listed as an example of inspection by a governmental agency in the proposed rule. The rule provides that an applicant will be deemed to meet the supervision by a governmental agency requirement if the governmental agency has statutory or regulatory authority to remove an applicant's officers or directors for malfeasance or misfeasance or otherwise exercise enforcement or administrative control over actions of the applicant. This removal factor was identified as an example of supervision by a governmental agency in the proposed rule.

Three commenters addressed the inspection and supervision requirement. A trade association commenter asked the Finance Board to include expressly legislative audits to meet the inspection requirement and removal by the governor to meet the supervision requirement. To accomplish the same end, a FHLBank commenter suggested defining the term ''governmental agency'' broadly to include the legislature and the governor. In response to these comments and to afford greater flexibility, the Finance Board has added a definition of the term ''governmental agency'' for purposes of this paragraph that includes the governor, legislature, and any other component of a federal, state, local, tribal, or Alaska Native village government with authority to act for or on behalf of that government. The third commenter asked whether a specific lender consortium that is examined jointly by federal and state financial institution regulators satisfies the supervision and inspection requirement. Without additional detailed information, the Finance Board cannot determine whether a particular entity meets the requirement. Under the final rule, the Banks would make this determination at the time an entity applies for certification as a nonmember mortgagee.

Under § 935.22(c)(4), an applicant is deemed to meet the mortgage activity requirement if it provides documentary evidence satisfactory to the FHLBank that it lends its own funds as its principal activity in the mortgage field. A financial statement that includes mortgage loan assets and their funding liabilities generally will provide adequate documentary evidence. Since this type of financial information is not readily available to the FHLBanks, the requirement for an applicant to submit documentation remains in the final rule. For purposes of this requirement, the Finance Board considers the purchase of whole mortgage loans tantamount to ''lending'' an applicant's funds. In the case of a federal, state, local, tribal, or Alaska Native village government agency, the Finance Board considers appropriated funds to be an applicant's ''own funds.'' An applicant will be deemed to satisfy this requirement even though the majority of its operations are unrelated to mortgage lending if its mortgage activity conforms to the regulatory criteria. A trade association commenter expressly supported the provision, stating that an applicant that acts principally as a broker for others making mortgage loans, or whose principal activity is to make mortgage loans for the account of others, does not meet this requirement.

Under § 935.22(c)(5), an applicant is deemed to meet the financial condition requirement if the FHLBank determines that advances may be extended safely to the applicant. In order to make that determination, the final rule requires an applicant to submit its most recent regulatory audit or examination report and external audit report. The Finance Board added a requirement to submit these specific financial documents in the final rule because a FHLBank commenter pointed out that applicants for FHLBank membership generally must submit such documents as part of their membership application, *see* 12 CFR 933.11, and that the information provided is often critical to analysis of an applicant's financial condition. The Bank also can require the applicant to submit additional documentary evidence, such as financial or other information.

3. State Housing Finance Agencies

In addition to meeting the eligibility requirements in § 935.22(b), any applicant seeking to take advantage of the more flexible collateral requirements for advances used to facilitate residential or commercial mortgage lending to certain low- and moderate-income families or individuals, must provide evidence satisfactory to the FHLBank that it is a SHFA as defined in § 935.1. *See supra* part II(A). Under § 935.22(d), satisfactory evidence generally consists of a copy of, or a citation to, the statutory and/or regulatory provisions outlining the applicant's structure and responsibilities. For the same reasons as discussed above for § 935.22(c)(2), the Finance Board has deleted the requirement that an applicant provide ''documentary'' evidence in the final rule.

E. Nonmember Mortgagee Applications

1. Devolution

As part of the Finance Board's continuing effort to devolve management and governance responsibilities to the FHLBanks, § 935.23(a) authorizes the FHLBanks to approve or deny all applications for certification as a nonmember mortgagee, subject to the requirements of the Bank Act and Finance Board regulations. Although all six commenters addressing this issue expressly supported devolution of decision making authority to the FHLBanks, one trade association commenter suggested delaying devolution until the FHLBanks have some experience in administering the final rule. Since the basis for the review criteria in the final rule is the standards previously applied by the FHLBanks and the Finance Board, no delay in devolution is required.

Four FHLBank commenters requested the authority to delegate application approvals to a committee of the FHLBank's board of directors, the FHLBank president, or a senior officer who reports directly to the president other than an officer responsible for business development. This would be consistent with the Finance Board's membership regulation and such authority is included in the final rule. *See* 12 CFR 933.3(a). Also consistent with the membership regulation, the final rule requires that only the FHLBanks' board of directors may deny certification as a nonmember mortgagee.

2. Application Process

The remainder of § 935.23 sets forth the procedures for submission and review of nonmember mortgagee applications. Section 935.23(b) requires an applicant to submit an application that satisfies the requirements of the Bank Act and this subpart to the FHLBank of the district in which the applicant's principal place of business, as determined in accordance with 12 CFR 933.18, is located.

To ensure expeditious action on applications for certification as a nonmember mortgagee, § 935.23(c)(1) requires a FHLBank to act on an application within 60 calendar days of the date the FHLBank deems the application complete. To make certain that the time period provided for review is not unduly restrictive, an application is deemed complete, thus triggering the 60-day time period, only after the FHLBank has obtained all required information and any other information it considers necessary to process the application. The rule permits the FHLBank to stop the 60-day period if it determines during the review process that additional information is necessary to process the application. The FHLBank must restart the 60-day time period where it stopped upon receiving the additional required information. The FHLBank must notify applicants in writing when the 60-day time period begins, stops, and starts again. One FHLBank commenter pointed out that under a parallel provision in the Finance Board's membership regulation, written notices are not required and requested similar treatment in this regulation. *See* 12 CFR 933.3(c). Written notice is necessary in order to provide an appropriate record for appellate and compliance review, therefore, the Finance Board is adopting the written notice requirement as proposed. Further, the Finance Board intends to clarify its membership regulation by including a written notice requirement in any future amendment.

Section 935.23(c)(2) requires the board of directors of the FHLBank, a duly delegated committee of the FHLBank's board of directors, the FHLBank president, or a senior officer who reports directly to the FHLBank president other than an officer with responsibility for business development to approve, or the board of directors of the FHLBank to deny, each application for certification as a nonmember mortgagee by a written decision resolution that states the grounds for the decision. In the proposed rule, the FHLBanks could not delegate certification approvals. As stated above, *see supra* part II(E)(1), the final rule prohibits delegation only of certification denials. The FHLBank must provide a copy of the decision resolution to the applicant and the Finance Board within three business days of the date of the decision on an application.

In order to provide an appropriate record for consideration of certification denial appeals and for determination by Finance Board examiners of a FHLBank's compliance with statutory and regulatory requirements, the Finance Board has added a new § 935.23(c)(3) that requires a FHLBank to maintain a certification file for each applicant. At a minimum, the certification file must include all documents submitted by the applicant or otherwise obtained or generated by the FHLBank concerning the applicant, all documents the Bank relied upon in making its certification determination, including copies of statutes and regulations, and the decision resolution. The FHLBank must retain the certification file for at least three years after the date of its decision to approve or deny certification or the date the Finance Board resolves any appeal, whichever is later. The Finance Board's membership rule includes a similar recordkeeping requirement. *See* 12 CFR 933.2(c).

To ensure that the FHLBanks apply the nonmember mortgagee eligibility requirements and review criteria uniformly and fairly and treat similarly situated applicants in a consistent manner, § 935.23(c)(4) establishes a process by which applicants may appeal FHLBank certification denials to the Finance Board. This provision appeared at § 935.23(c)(3) in the proposed rule. Within 90 calendar days of the date of a FHLBank's certification denial, an applicant may submit a written appeal to the Finance Board with a copy to the FHLBank. The appeal must include the FHLBank's decision resolution and a statement of the basis for the appeal with sufficient facts, information, analysis, and explanation to support the applicant's position. The FHLBank whose action has been appealed must submit to the Finance Board a complete copy of the applicant's certification file as well as any relevant new materials it receives while the appeal is pending. The rule authorizes the Finance Board to request any additional information or supporting arguments it may require to decide the appeal. The Finance Board must make its decision within 90 calendar days of the date the applicant files an appeal.

F. Advances to Nonmember Mortgagees

Section 935.24 establishes the terms and conditions under which a FHLBank may make advances to a nonmember mortgagee. Under § 935.24(a), a FHLBank may lend only to a nonmember mortgagee whose principal place of business is located in the FHLBank's district.

1. Collateral Requirements in General

Section 935.24(b) sets forth the collateral requirements for advances to nonmember mortgagees. Pursuant to section 10b(a) of the Bank Act, 12 U.S.C. 1430b(a), and § 935.24(b)(1) of the final rule, a FHLBank may make advances to any nonmember mortgagee upon the security of FHA-insured mortgages, including securities representing a whole interest in a pool of FHA-insured mortgages, if the nonmember mortgagee provides evidence satisfactory to the FHLBank that the securities are backed solely by qualifying mortgages.

2. SHFA Collateral Requirements

Section 935.24(b)(2) implements the less restrictive collateral requirements applicable to advances to a SHFA nonmember mortgagee, the proceeds of which will be used to facilitate mortgage lending that benefits certain low- and moderate-income individuals or families. *See supra* part I; 12 U.S.C. 1430b(b). Under § 935.24(b)(2)(i), a FHLBank may secure qualifying advances with: the collateral described in § 935.24(b)(1); collateral eligible under categories 1 or 2 of Bank Act section 10(a), 12 U.S.C. 1430(a)(1)–(2), as described in 12 CFR 935.9(a)(1) or (2); or, collateral eligible under category 4 of Bank Act section 10(a), 12 U.S.C. 1430(a)(4), as described in 12 CFR 935.9(a)(4), provided that such collateral is comprised of mortgage loans on one-to-four or multi-family residential property and the acceptance of such collateral will not increase the total amount of advances outstanding to the SHFA secured by such collateral beyond 30 percent of its GAAP capital, as computed by the FHLBank. A FHLBank commenter recommended that the rule specifically include as acceptable collateral for SHFA advances, collateral pledged by a FHLBank member to secure its obligations under a standby letter of credit issued for the benefit of a FHLBank that makes a SHFA nonmember mortgagee advance. The current Finance Board regulation concerning collateral for advances does not address this type of collateral. *See* 12 CFR 935.9. The Finance Board plans to consider this issue as part of a future rulemaking concerning FHLBank advances.

The proposed rule asserted that SHFA nonmember mortgagees would not have any Bank Act section 10(a) category 3 collateral available to secure FHLBank advances since a FHLBank may accept deposits only from FHLBank members, other FHLBanks, or other instrumentalities of the United States. *See* 12 U.S.C. 1430(a)(3), 1431(e)(1); 61 FR 52731. Three FHLBank commenters found this interpretation of the Bank Act overly restrictive. For the following reasons, the Finance Board agrees.[3] Section 10b(b) of the Bank Act

[3] The statement in the preamble to the proposed rule regarding acceptance of deposits from nonmember mortgagees was not meant to preclude a FHLBank from accepting deposits under section 11(e)(2) of the Bank Act for the purpose of providing correspondent banking services, provided that the nonmember mortgagee is an institution eligible to make application to become a FHLBank member. *See* 12 U.S.C. 1431(e)(2).

authorizes the FHLBanks to accept collateral that meets the requirements of section 10(a) to secure qualifying advances to SHFA nonmember mortgagees. *See* 12 U.S.C. 1430b(b). Section 10(a) of the Bank Act includes specifically deposits in a FHLBank as acceptable collateral. *See id.* 1430(a). The Finance Board believes that there is statutory authority to allow SHFA nonmember mortgagees to secure qualifying advances with cash collateral in the form of FHLBank deposits. Accordingly, the Finance Board has added a new paragraph, § 935.24(b)(2)(B), authorizing the FHLBanks to accept deposits in a FHLBank as security for SHFA nonmember mortgagee advances. Pursuant to the FHLBanks' incidental authority to do all things necessary to carry out the provisions of the Bank Act, *see* 12 U.S.C. 1431(a), (e)(1), and to facilitate acceptance of such collateral, the rule permits the FHLBanks to establish cash collateral accounts for SHFA nonmember mortgagees. This interpretation is consistent with the restriction on acceptance of deposits by the FHLBanks contained in section 11(e)(1) of the Bank Act, *see id.* 1431(e)(1), since the SHFA nonmember mortgagee will use the cash collateral account at the FHLBank only to secure advances and not to take advantage of FHLBank deposit programs, *i.e.*, SHFA nonmember mortgagees will not be able to use a FHLBank as a substitute for a commercial bank.

If a SHFA nonmember mortgagee wishes to pledge other than FHA-insured collateral, § 935.24(b)(2)(ii) requires it to certify first in writing to the FHLBank that it will use the proceeds of the advance so secured to facilitate qualifying mortgage lending. The final rule clarifies that qualifying mortgage lending includes both residential and commercial mortgage lending. A trade association commenter expressly supported this provision because it will allow SHFA nonmember mortgagees to help small businesses and promote economic development efforts.

3. Terms and Conditions for Advances

Section 935.24(c) outlines the terms and conditions for advances to nonmember mortgagees. Under § 935.24(c)(1), a FHLBank may exercise its discretion to determine whether, and on what terms, it will make advances to nonmember mortgagees. Section 935.24(c)(2) addresses advance pricing. The provision in the proposed rule requiring the FHLBanks to apply pricing criteria other than cost and credit risk to nonmember mortgagee advances in the same manner as they apply those criteria to member advances was intended to make clear that the FHLBanks must treat all of their member and nonmember borrowers equally. One commenter thought the rule should expressly require the FHLBanks to price advances to SHFA nonmember mortgagees, given their public purpose, at the same rate as member advances. To ensure equal treatment, the final rule specifically applies the advance pricing requirements applicable to member advances to nonmember mortgagee advances. Accordingly, paragraph (c)(2)(i) requires a FHLBank to price advances to nonmember mortgagees in accordance with the requirements of § 935.6(b), the advance pricing requirements for member advances. It provides that the term ''member'' as used in § 935.6(b), also means ''nonmember'' for purposes of this section. Paragraph (c)(2)(ii) of the final rule requires a FHLBank to apply the pricing criteria that appear in § 935.6(b)(2), including credit and other risks of lending to a particular borrower and other reasonable differential pricing criteria, equally to all of its member and nonmember borrowers. The pricing criteria that appeared in the proposed rule are included in § 935.6(b).

The Finance Board proposed deleting the current requirement that nonmember mortgagee advances be priced to compensate a FHLBank for the lack of a capital stock investment in the FHLBank by the nonmember mortgagee. *See* 12 CFR 935.22(e)(2)(B)(ii); 61 FR 52731. The preamble to the proposed rule stated that such compensation was unnecessary since the additional earnings achieved through advances not supported by capital should enhance a FHLBank's return on equity. Seven commenters addressed this issue. Two commenters supported the proposal because the compensation mark-up strongly discourages nonmember mortgagees from using FHLBank advances. Four commenters recommended deletion of the requirement and replacement with a provision giving the FHLBanks discretion to adjust nonmember mortgagee advance prices by either requiring a compensating balance or including compensation for the lack of a capital stock investment as a reasonable pricing differential criteria in § 935.24(c)(3)(iii). One commenter believed that the requirement should remain in the rule.

The comments advocating a special mark-up on nonmember mortgagee advances generally highlighted three concerns. The first concern was that the added leverage associated with nonmember mortgagee advances creates additional risk for which members should be compensated. For the following reasons, the Finance Board finds this argument to be unpersuasive. In order for nonmember lending to have a material impact on a FHLBank's leverage, the amount of advances outstanding to nonmember mortgagees would have to increase significantly over current levels. For example, advances to nonmember mortgagees at the FHLBank with the largest volume of such advances outstanding at the end of 1996 represented 0.1 percent of the FHLBank's total assets and 2 percent of its capital. In addition, fully secured nonmember mortgagee advances involve minimal credit risk. Therefore, the mark-up necessary to compensate members for any increased risk resulting from greater leverage would almost certainly be *de minimis*.

The second concern expressed generally by commenters was that, depending upon the relationship between the return paid on FHLBank stock, a member's alternative investments, and the cost of debt, a nonmember mortgagee might have a financial advantage from FHLBank borrowings that would allow it to compete for mortgages with members. For the following reasons, the Finance Board finds this argument to be unpersuasive. On the basis of the strong growth in voluntary membership since 1990, it appears that FHLBank dividend rates generally exceed the alternative investment rates available to members. For example, the average FHLBank dividend rate in 1996 was 120 basis points over the average one-year Treasury security and, since fourth quarter 1989, only two FHLBanks on eight occasions have paid a quarterly dividend rate below the average federal funds rate. Accordingly, investing in FHLBank stock typically should not put a member at a competitive disadvantage relative to nonmember mortgagees.

The third concern advanced by commenters in support of a compensation mark-up is that funding nonmember mortgagee advances may be more expensive to the extent that the cost of debt is higher than the mixture of debt and equity used to fund member advances. This argument also is unpersuasive. With few exceptions, FHLBank debt has been less expensive than equity, thus, advances funded solely with debt should be less expensive than those funded with a mix of equity and debt. In addition, under § 935.24(c)(2)(i), the FHLBanks must price a nonmember mortgagee advance to cover the funding, operating, and administrative costs associated with making the advance.

After consideration of the comments, the Finance Board has determined that, given the current financial operations of the FHLBanks, there do not appear to be compelling economic circumstances to justify an additional compensation mark-up on nonmember mortgagee advances. Further, eliminating the mark-up should enhance the FHLBanks' statutory housing finance mission by providing more attractively priced funds to entities that specialize in affordable housing finance. Accordingly, the lack of a capital stock investment in a FHLBank by a nonmember borrower is not an acceptable other risk or differential pricing factor. If a FHLBank is able to show in a particular case that it will suffer financial hardship as a result of lending to a nonmember mortgagee, and is able to quantify the harm, it may request a regulatory waiver. *See* 61 FR 64613 (Dec. 6, 1996), *codified at* 12 CFR 902.6.

Two commenters asked the Finance Board to clarify whether a FHLBank is required or has discretion to allow a nonmember mortgagee to participate in a FHLBank's Community Investment Program (CIP). Both commenters thought that the FHLBanks should grant SHFA nonmember mortgagees access to advances at CIP rates. Section 10(i) of the Bank Act requires each FHLBank to ''establish a program to provide funding for *members* to undertake community-oriented mortgage lending.'' *See id.* 1430(i)(1) (emphasis added). Since the final rule gives the FHLBanks discretion in pricing nonmember mortgagee advances, the FHLBanks could make advances at CIP rates available to nonmember mortgagees. However, because section 10(i)(1) requires establishment of a CIP only for members, the FHLBanks are not required to do so. The Finance Board plans to consider this issue as part of a future rulemaking concerning CIP advance programs.

Section 935.24(c)(3) limits the principal amount of any advance made to a nonmember mortgagee to 90 percent of the unpaid principal of the mortgage loans or securities pledged as security for the advance. This limit does not apply to advances made to SHFA nonmember mortgagees for the purpose of facilitating qualifying low- and moderate-income mortgage lending. A trade association commented that a principal reason limiting nonmember borrowing is that most FHLBanks value nonmember mortgagee collateral at levels below the 90 percent limit. The Finance Board believes that the FHLBanks should develop the technical capacity to evaluate more precisely the risks of multi-family mortgages. This potentially will lower the over-collateralization factor assigned to such collateral.

4. Transaction Accounts

A FHLBank commenter suggested that the rule be revised to include authority for the FHLBanks to establish transaction accounts with nonmember mortgagees in order to facilitate the funding of advances. Since the FHLBanks have incidental authority to establish limited purposes deposit accounts, *see supra* part II(F)(2), the Finance Board has added a new paragraph § 935.24(d) to provide the suggested authorization.

5. Ineligibility

Under certain circumstances certified nonmember mortgagees may become ineligible to receive FHLBank advances. Section 935.24(e)(1) requires a nonmember mortgagee that applies for an advance to agree first in writing that it will promptly notify the FHLBank of any change in its status as a nonmember mortgagee. Section 935.24(e)(2) permits a FHLBank, from time to time, to require a nonmember mortgagee to provide evidence that it continues to satisfy all of the statutory and regulatory eligibility requirements. If the FHLBank determines that the nonmember mortgagee no longer meets the eligibility requirements, § 935.24(e)(3) prohibits the FHLBank from extending a new advance or renewing an existing advance until the entity provides evidence satisfactory to the FHLBank that it is in compliance with such requirements. The Finance Board received no comments regarding these provisions and is adopting them without change from the proposal.

III. Regulatory Flexibility Act

The rule largely implements statutory requirements binding on all FHLBanks, nonmember mortgagee applicants, and certified nonmember mortgagees. The Finance Board is not at liberty to make adjustments in the requirements to accommodate small entities. The Finance Board has not imposed any additional regulatory requirements that will have a disproportionate impact on small entities. Thus, in accordance with the provisions of the Regulatory Flexibility Act, the Board of Directors of the Finance Board hereby certifies that this final rule will not have a significant economic impact on a substantial number of small entities. 5 U.S.C. 605(b).

IV. Paperwork Reduction Act

As part of the notice of proposed rulemaking, the Finance Board published a request for comments concerning the collection of information contained in §§ 935.22 through 935.24 of the proposed rule. *See* 61 FR 52731. The Finance Board received no comments regarding the collection of information. The Finance Board also submitted an analysis of the information collection to the Office of Management and Budget (OMB) for review in accordance with section 3507(d) of the Paperwork Reduction Act of 1995. *See* 44 U.S.C. 3507(d). OMB assigned a control number, 3069–0005, and approved the information collection without conditions with an expiration date of November 30, 1999. Potential respondents are not required to respond to the collection of information unless the regulation collecting the information displays a currently valid control number assigned by the OMB. *See id.* 3512(a). The final rule does not substantively or materially modify the approved information collection. The title, description of need and use, and a description of the information collection requirements in the final rule are discussed in parts I and II of the **SUPPLEMENTARY INFORMATION.**

The following table discloses the estimated annual reporting and recordkeeping burden:

The estimated annual reporting and recordkeeping hour burden is:	
a. Number of respondents	10
b. Total annual responses	10
Percentage collected electronically	0
c. Total annual hours requested	100
d. Current OMB inventory	100
e. Difference	0
The estimated annual reporting and recordkeeping cost burden is:	
a. Total annualized capital/start-up costs	$ 0
b. Total annual costs (O&M)	0
c. Total annualized cost requested	6,250
d. Current OMB inventory	6,250
e. Difference	0

Any comments concerning the information collection should be submitted to Elaine L. Baker, Executive Secretary, Federal Housing Finance Board, 1777 F Street, N.W., Washington, D.C. 20006, and the Office of Information and Regulatory Affairs of the Office of Management and Budget, Attention: Desk Officer for Federal Housing Finance Board, Washington, D.C. 20503.

List of Subjects in 12 CFR Part 935

Credit, Federal home loan banks, Reporting and recordkeeping requirements.

Accordingly, the Board of Directors of the Federal Housing Finance Board hereby amends part 935, chapter IX, title 12 of the Code of Federal Regulations, as follows:

PART 935—ADVANCES

1. The authority citation for part 935 is revised to read as follows:

Authority: 12 U.S.C. 1422a(a)(3), 1422b(a)(1), 1426, 1429, 1430, 1430b, and 1431.

2. Section 935.1 is amended by revising the definition of ''State housing finance agency'' to read as follows:

§ 935.1 Definitions.

* * * * *

State housing finance agency or *SHFA* means:

(1) A public agency, authority, or publicly sponsored corporation that serves as an instrumentality of any state or political subdivision of any state, and functions as a source of residential mortgage loan financing in that state; or

(2) A legally established agency, authority, corporation, or organization that serves as an instrumentality of any Indian tribe, band, group, nation, community, or Alaska Native village recognized by the United States or any state, and functions as a source of residential mortgage loan financing for the Indian or Alaska Native community.

* * * * *

3. Subpart B is revised to read as follows:

Subpart B—Advances to Nonmembers

Sec.
935.20 Advances to the Savings Association Insurance Fund.
935.21 Scope.
935.22 Nonmember mortgagee eligibility requirements.
935.23 Nonmember mortgagee application process.
935.24 Advances to nonmember mortgagees.

Subpart B—Advances to Nonmembers

§ 935.20 Advances to the Savings Association Insurance Fund.

(a) *Authority.* Upon receipt of a written request from the FDIC, a Bank may make advances to the FDIC for the use of the SavingsAssociation Insurance Fund. The Bank shall provide a copy of such request to the Board.

(b) *Requirements.* Advances to the FDIC for the use of the Savings Association Insurance Fund shall:

(1) Bear a rate of interest not less than the Bank's marginal cost of funds, taking into account the maturities involved and reasonable administrative costs;

(2) Have a maturity acceptable to the Bank;

(3) Be subject to any prepayment, commitment, or other appropriate fees of the Bank; and

(4) Be adequately secured by collateral acceptable to the Bank.

§ 935.21 Scope.

With the exception of § 935.13, and except as otherwise provided in § 935.20 and § 935.24, the requirements of subpart A of this part apply to this subpart.

§ 935.22 Nonmember mortgagee eligibility requirements.

(a) *Authority.* Subject to the provisions of the Act and this subpart, a Bank may make advances to an entity that is not a member of the Bank if the Bank has certified the entity as a nonmember mortgagee.

(b) *Eligibility requirements.* A Bank may certify as a nonmember mortgagee any applicant that meets the following requirements:

(1) The applicant is approved under title II of the National Housing Act (12 U.S.C. 1707, *et seq.*);

(2) The applicant is a chartered institution having succession;

(3) The applicant is subject to the inspection and supervision of some governmental agency;

(4) The principal activity of the applicant in the mortgage field consists of lending its own funds; and

(5) The financial condition of the applicant is such that advances may be safely made to it.

(c) *Satisfaction of eligibility requirements*—(1) *HUD approval requirement.* An applicant shall be deemed to meet the requirement in section 10b(a) of the Act and paragraph (b)(1) of this section that it be approved under title II of the National Housing Act if it submits a current HUD Yearly Verification Report or other documentation issued by HUD stating that the Federal Housing Administration of HUD has approved the applicant as a mortgagee.

(2) *Charter requirement.* An applicant shall be deemed to meet the requirement in section 10b(a) of the Act and paragraph (b)(2) of this section that it be a chartered institution having succession if it provides evidence satisfactory to the Bank, such as a copy of, or a citation to, the statutes and/or regulations under which the applicant was created, that:

(i) The applicant is a government agency; or

(ii) The applicant is chartered under state, federal, local, tribal, or Alaska Native village law as a corporation or other entity that has rights, characteristics, and powers under applicable law similar to those granted a corporation.

(3) *Inspection and supervision requirement.* An applicant shall be deemed to meet the inspection and supervision requirement in section 10b(a) of the Act and paragraph (b)(3) of this section if it provides evidence satisfactory to the Bank, such as a copy of, or a citation to, relevant statutes and/or regulations, that, pursuant to statute or regulation, the applicant is subject to the inspection and supervision of a federal, state, local, tribal, or Alaska native village governmental agency. An applicant shall be deemed to meet the inspection requirement if there is a statutory or regulatory requirement that the applicant be audited or examined periodically by a governmental agency or by an external auditor. An applicant shall be deemed to meet the supervision requirement if the governmental agency has statutory or regulatory authority to remove an applicant's officers or directors for cause or otherwise exercise enforcement or administrative control over actions of the applicant. For purposes of this paragraph (c)(3), the term ''governmental agency'' includes the governor, legislature, and any other component of a federal, state, local, tribal, or Alaska native village government with authority to act for or on behalf of that government.

(4) Mortgage activity requirement. An applicant shall be deemed to meet the mortgage activity requirement in section 10b(a) of the Act and paragraph (b)(4) of this section if it provides documentary evidence satisfactory to the Bank, such as a financial statement or other financial documents that include the applicant's mortgage loan assets and their funding liabilities, that it lends its own funds as its principal activity in the mortgage field. Lending funds includes, but is not limited to, the purchase of whole mortgage loans. In the case of a federal, state, local, tribal, or Alaska Native village government agency, appropriated funds shall be considered an applicant's own funds. An applicant shall be deemed to satisfy this requirement notwithstanding that the majority of its operations are unrelated to mortgage lending if its mortgage activity conforms to this requirement. An applicant that acts principally as a broker for others making mortgage loans, or whose principal activity is to make mortgage loans for the account of others, does not meet this requirement.

(5) *Financial condition requirement.* An applicant shall be deemed to meet the financial condition requirement in

paragraph (b)(5) of this section if the Bank determines that advances may be safely made to the applicant. The applicant shall submit to the Bank copies of its most recent regulatory audit or examination report, or external audit report, and any other documentary evidence, such as financial or other information, that the Bank may require to make the determination.

(d) *State housing finance agencies.* In addition to meeting the requirements in paragraph (b) of this section, any applicant seeking access to advances as a SHFA pursuant to § 935.24(b)(2) shall provide evidence satisfactory to the Bank, such as a copy of, or a citation to, the statutes and/or regulations describing the applicant's structure and responsibilities, that the applicant is a state housing finance agency as defined in § 935.1.

(e) *Ineligibility.* Except as otherwise provided in this subpart, if an applicant does not satisfy the requirements of this subpart, the applicant is ineligible to be certified as a nonmember mortgagee.

(The Office of Management and Budget approved the information collection requirements contained in this section and assigned control number 3069–0005 with an expiration date of November 30, 1999)

§ 935.23 Nonmember mortgagee application process.

(a) *Authority.* The Banks are authorized to approve or deny all applications for certification as a nonmember mortgagee, subject to the requirements of the Act and this subpart. A Bank may delegate the authority to approve applications for certification as a nonmember mortgagee only to a committee of the Bank's board of directors, the Bank president, or a senior officer who reports directly to the Bank president other than an officer with responsibility for business development.

(b) *Application requirements.* An applicant for certification as a nonmember mortgagee shall submit an application that satisfies the requirements of the Act and this subpart to the Bank of the district in which the applicant's principal place of business, as determined in accordance with part 933 of this chapter, is located.

(c) *Application process*—(1) *Action on applications.* A Bank shall approve or deny an application for certification as a nonmember mortgagee within 60 calendar days of the date the Bank deems the application to be complete. A Bank shall deem an application complete, and so notify the applicant in writing, when it has obtained all of the information required by this subpart and any other information it deems necessary to process the application. If a Bank determines during the review process that additional information is necessary to process the application, the Bank may deem the application incomplete and stop the 60-day time period by providing written notice to the applicant. When the Bank receives the additional information, it shall again deem the application complete, so notify the applicant in writing, and resume the 60-day time period where it stopped.

(2) *Decision on applications.* The Bank or a duly delegated committee of the Bank's board of directors, the Bank president, or a senior officer who reports directly to the Bank president other than an officer with responsibility for business development shall approve, or the board of directors of a Bank shall deny, each application for certification as a nonmember mortgagee by a written decision resolution stating the grounds for the decision. Within three business days of a Bank's decision on an application, the Bank shall provide the applicant and the Board with a copy of the Bank's decision resolution.

(3) *File.* The Bank shall maintain a certification file for each applicant for at least three years after the date the Bank decides whether to approve or deny certification or the date the Board resolves any appeal, whichever is later. At a minimum, the certification file shall include all documents submitted by the applicant or otherwise obtained or generated by the Bank concerning the applicant, all documents the Bank relied upon in making its determination regarding certification, including copies of statutes and regulations, and the decision resolution.

(4) *Appeals.* Within 90 calendar days of the date of a Bank's decision to deny an application for certification as a nonmember mortgagee, the applicant may submit a written appeal to the Board that includes the Bank's decision resolution and a statement of the basis for the appeal with sufficient facts, information, analysis, and explanation to support the applicant's position. Appeals shall be sent to the Federal Housing Finance Board, 1777 F Street, N.W., Washington D.C. 20006, with a copy to the Bank.

(i) *Record for appeal.* Upon receiving a copy of an appeal, the Bank whose action has been appealed shall provide to the Board a complete copy of the applicant's certification file maintained by the Bank under paragraph (c)(3) of this section. Until the Board resolves the appeal, the Bank shall promptly provide to the Board any relevant new materials it receives. The Board may request additional information or further supporting arguments from the applicant, the Bank, or any other party that the Board deems appropriate.

(ii) *Deciding appeals.* Within 90 calendar days of the date an applicant files an appeal with the Board, the Board shall consider the record for appeal described in paragraph (c)(4)(i) of this section and resolve the appeal based on the requirements of the Act and this subpart.

(The Office of Management and Budget approved the information collection requirements contained in this section and assigned control number 3069–0005 with an expiration date of November 30, 1999)

§ 935.24 Advances to nonmember mortgagees.

(a) *Authority.* Subject to the provisions of the Act and this subpart, a Bank may make advances only to a nonmember mortgagee whose principal place of business, as determined in accordance with part 933 of this chapter, is located in the Bank's district.

(b) *Collateral requirements*—(1) *Advances to nonmember mortgagees.* A Bank may make an advance to any nonmember mortgagee upon the security of the following collateral:

(i) Mortgage loans insured by the Federal Housing Administration of HUD under title II of the National Housing Act; or

(ii) Securities representing a whole interest in the principal and interest payments due on a pool of mortgage loans insured by the Federal Housing Administration of HUD under title II of the National Housing Act. A Bank may only accept as collateral the securities described in this paragraph (b)(1)(ii) if the nonmember mortgagee provides evidence that such securities are backed solely by mortgages of the type described in paragraph (b)(1)(i) of this section.

(2) *Certain advances to SHFAs.* (i) In addition to the collateral described in paragraph (b)(1) of this section, a Bank may make an advance to a nonmember mortgagee that has satisfied the requirements of § 935.22(d) for the purpose of facilitating residential or commercial mortgage lending that benefits individuals or families meeting the income requirements in section 142(d) or 143(f) of the Internal Revenue Code (26 U.S.C. 142(d) or 143(f)) upon the security of the following collateral:

(A) The collateral described in § 935.9(a)(1) or (2).

(B) The collateral described in § 935.9(a)(3). Solely for the purpose of facilitating acceptance of such collateral, a Bank may establish a cash collateral account for a nonmember mortgagee that has satisfied the requirements of § 935.22(d).

(C) The real estate related collateral described in § 935.9(a)(4), provided that such collateral is comprised of mortgage loans on one-to-four family or multifamily residential property and the acceptance of such collateral will not increase the total amount of advances outstanding to the SHFA secured by such collateral beyond 30 percent of its GAAP capital, as computed by the Bank.

(ii) Prior to making an advance pursuant to this paragraph (b)(2), a Bank shall obtain a written certification from the nonmember mortgagee that it shall use the proceeds of the advance for the purposes described in paragraph (b)(2)(i) of this section.

(c) *Terms and conditions*—(1) *General.* Subject to the provisions of this paragraph (c), a Bank, in its discretion, shall determine whether, and on what terms, it will make advances to a nonmember mortgagee.

(2) *Advance pricing.* (i) A Bank shall price advances to nonmember mortgagees in accordance with the requirements for pricing advances to members set forth in § 935.6(b). Wherever the term ''member'' appears in § 935.6(b), the term shall be construed also to mean ''nonmember mortgagee.''

(ii) A Bank shall apply the pricing criteria identified in § 936.5(b)(2) equally to all of its member and nonmember mortgagee borrowers.

(3) *Limit on advances.* The principal amount of any advance made to a nonmember mortgagee may not exceed 90 percent of the unpaid principal of the mortgage loans or securities pledged as security for the advance. This limit does not apply to an advance made to a nonmember mortgagee under paragraph (b)(2) of this section.

(d) *Transaction accounts.* Solely for the purpose of facilitating the making of advances to a nonmember mortgagee, a Bank may establish a transaction account for each nonmember mortgagee.

(e) *Loss of eligibility*—(1) *Notification of status changes.* A Bank shall require a nonmember mortgagee that applies for an advance to agree in writing that it will promptly inform the Bank of any change in its status as a nonmember mortgagee.

(2) *Verification of eligibility.* A Bank may, from time to time, require a nonmember mortgagee to provide evidence that it continues to satisfy all of the eligibility requirements of the Act and this subpart.

(3) *Loss of eligibility.* A Bank shall not extend a new advance or renew an existing advance to a nonmember mortgagee that no longer meets the eligibility requirements of the Act and this subpart until the entity has provided evidence satisfactory to the Bank that it is in compliance with such requirements.

(The Office of Management and Budget approved the information collection requirements contained in this section and assigned control number 3069–0005 with an expiration date of November 30, 1999)

By the Board of Directors of the Federal Housing Finance Board.

Dated: February 19, 1997.

Bruce A. Morrison,

Chairperson.

[FR Doc. 97–6260 Filed 3–13–97; 8:45 am]

BILLING CODE 6725–01–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. 96–NM–117–AD; Amendment 39–9964; AD 97–06–07]

RIN 2120–AA64

Airworthiness Directives; Dornier Model 328–100 Series Airplanes Equipped With Burns Aerospace Corporation Passenger Seats

AGENCY: Federal Aviation Administration, DOT.

ACTION: Final rule.

SUMMARY: This amendment adopts a new airworthiness directive (AD), applicable to certain Dornier Model 328–100 series airplanes, that requires modification of the restraining systems of certain passenger seats by replacing anchor point fasteners with fasteners that are able to withstand required 16g load conditions. This amendment is prompted by a report indicating that the restraining systems on these seats failed to meet 16g test load requirements during dynamic testing. The actions specified by this AD are intended to prevent the fasteners from failing, which could result in release of the seat restraint and consequent injury to passengers.

DATES: Effective April 18, 1997.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of April 18, 1997.

ADDRESSES: The service information referenced in this AD may be obtained from Dornier Luftfahrt GmbH, P.O. Box 1103, D–82230 Wessling, Germany. This information may be examined at the Federal Aviation Administration (FAA), Transport Airplane Directorate, Rules Docket, 1601 Lind Avenue, SW., Renton, Washington; or at the Office of the Federal Register, 800 North Capitol Street, NW., suite 700, Washington, DC.

FOR FURTHER INFORMATION CONTACT: Connie Beane, Aerospace Engineer, Standardization Branch, ANM–113, FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington 98055–4056; telephone (206) 227–2796; fax (206) 227–1149.

SUPPLEMENTARY INFORMATION: A proposal to amend part 39 of the Federal Aviation Regulations (14 CFR part 39) to include an airworthiness directive (AD) that is applicable to certain Dornier Model 328–100 series airplanes was published in the Federal Register on December 13, 1996 (61 FR 65494). That action proposed to require removal of the anchor point fasteners on Burns Aerospace Corporation commuter seat models JB6.8–1–22 and JB6.8–2–42 passenger seats. It proposed replacing the fasteners with new ones which will ensure that the restraining system for these seats is able to withstand the required 16g test load conditions.

Interested persons have been afforded an opportunity to participate in the making of this amendment. No comments were submitted in response to the proposal or the FAA's determination of the cost to the public.

Conclusion

The FAA has determined that air safety and the public interest require the adoption of the rule as proposed.

Cost Impact

The FAA estimates that 36 Dornier Model 328–100 airplanes of U.S. registry will be affected by this AD, that it will take approximately 1 work hour per seat to accomplish the required actions, and that the average labor rate is $60 per work hour. There are normally 30 seats per airplane. Required parts will be provided by the manufacturer at no cost to operators. Based on these figures, the cost impact of the AD on U.S. operators is estimated to be $64,800, or $1,800 per airplane.

The cost impact figure discussed above is based on assumptions that no operator has yet accomplished any of the requirements of this AD action, and that no operator would accomplish those actions in the future if this AD were not adopted.

Regulatory Impact

The regulations adopted herein will not have substantial direct effects 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. Therefore, in accordance with Executive Order 12612, it is determined that this final rule does not have sufficient federalism implications to warrant the preparation of a Federalism Assessment.

For the reasons discussed above, I certify that this action (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. A final evaluation has been prepared for this action and it is contained in the Rules Docket. A copy of it may be obtained from the Rules Docket at the location provided under the caption **ADDRESSES.**

List of Subjects in 14 CFR Part 39

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

Adoption of the Amendment

Accordingly, pursuant to 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. Section 39.13 is amended by adding the following new airworthiness directive:

97–06–07 Dornier: Amendment 39–9964. Docket 96–NM–117–AD.

Applicability: Model 328–100 series airplanes equipped with Burns Aerospace Corporation commuter seat models JB6.8–1–22 and JB6.8–2–42 passenger seats; certificated in any category.

Note 1: This AD applies to each airplane identified in the preceding applicability provision, regardless of whether it has been otherwise modified, altered, or repaired in the area subject to the requirements of this AD. For airplanes that have been modified, altered, or repaired so that the performance of the requirements of this AD is affected, the owner/operator must request approval for an alternative method of compliance in accordance with paragraph (b) of this AD. The request should include an assessment of the effect of the modification, alteration, or repair on the unsafe condition addressed by this AD; and, if the unsafe condition has not been eliminated, the request should include specific proposed actions to address it.

Compliance: Required as indicated, unless accomplished previously.

To prevent failure of the anchor point fasteners on the seat restraining systems, which could result in release of the seat restraint and consequent injury to passengers, accomplish the following:

(a) Within 60 days after the effective date of this AD, replace each anchor point fastener on the restraining system of each seat with a fastener of improved design, in accordance with Dornier Service Bulletin SB–328–25–114, dated July 10, 1995.

Note 2: The Dornier service bulletin references Burns Aerospace Corporation Service Bulletin SB–25–20–989, Revision B, dated June 14, 1995, as an additional source of procedural service information for replacement of the anchor point fasteners.

(b) An alternative method of compliance or adjustment of the compliance time that provides an acceptable level of safety may be used if approved by the Manager, Standardization Branch, ANM–113, FAA, Transport Airplane Directorate. Operators shall submit their requests through an appropriate FAA Principal Maintenance Inspector, who may add comments and then send it to the Manager, Standardization Branch, ANM–113.

Note 3: Information concerning the existence of approved alternative methods of compliance with this AD, if any, may be obtained from the Standardization Branch, ANM–113.

(c) Special flight permits may be issued in accordance with sections 21.197 and 21.199 of the Federal Aviation Regulations (14 CFR 21.197 and 21.199) to operate the airplane to a location where the requirements of this AD can be accomplished.

(d) The replacement shall be done in accordance with Dornier Service Bulletin SB–328–25–114, dated July 10, 1995. This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. Copies may be obtained from Dornier Luftfahrt GmbH, P.O. Box 1103, D–82230 Wessling, Germany. Copies may be inspected at the FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington; or at the Office of the Federal Register, 800 North Capitol Street, NW., suite 700, Washington, DC.

(e) This amendment becomes effective on April 18, 1997.

Issued in Renton, Washington, on March 6, 1997.

Neil D. Schalekamp,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 97–6262 Filed 3–13–97; 8:45 am]

BILLING CODE 4910–13–U

14 CFR Part 71

[Airspace Docket No. 96–ASW–20]

Revision of Class E Airspace; Gallup, NM

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This action revises the Class E airspace extending upward from 700 feet above ground level (AGL) at Gallup, NM. The development of a Global Positioning System (GPS) Standard Instrument Approach Procedure (SIAP) to Runway (RWY) 24 at Gallup Municipal Airport has made this action necessary. This action is intended to provide adequate Class E airspace to contain instrument flight rule (IFR) operations for aircraft executing the GPS SIAP to RWY 24 at Gallup Municipal Airport, Gallup, NM.

EFFECTIVE DATE: 0901 UTC, May 22, 1997.

FOR FURTHER INFORMATION CONTACT: Donald J. Day, Operations Branch, Air Traffic Division, Southwest Region, Federal Aviation Administration, Fort Worth, TX 76193–0530, telephone 817–222–5593.

SUPPLEMENTARY INFORMATION:

History

On November 22, 1996, a proposal to amend part 71 of the Federal Aviation Regulations (14 CFR part 71) to revise the Class E airspace at Gallup, NM, was published in the Federal Register (61 FR 59383). A GPS SIAP to RWY 24 developed for Gallup Municipal Airport, Gallup NM, requires the revision of the Class E airspace at this airport. The proposal was to revise the controlled airspace extending upward from 700 feet AGL to contain IFR operations in controlled airspace during portions of the terminal operation and while transitioning between the enroute and terminal environments.

Interested parties were invited to participate in this rulemaking proceeding by submitting written comments on the proposal to the FAA. No comments to the proposal were received. The rule is adopted as proposed.

The coordinates for this airspace docket are based on North American Datum 83. Class E airspace designations for airspace areas extending upward from 700 feet or more AGL are published in Paragraph 6005 of FAA Order 7400.9D dated September 4, 1996, and effective September 16, 1996, 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 part 71 of the Federal Aviation Regulations (14 CFR part 71) amends the Class E airspace located at Gallup Municipal Airport, Gallup, NM, to provide controlled airspace extending upward from 700 feet AGL for aircraft executing the GPS SIAP to RWY 24.

The FAA has determined that this regulation only involves an established body of technical regulations that need frequent and routine amendments 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 11035; 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 will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

List of Subject 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—[AMENDED]

1. The authority citation for 14 CFR part 71 continues to read as follows:

AUTHORITY: 49 U.S.C. 40103, 40113, 40120; E.O. 10854; 24 FR 9565, 3 CFR, 1959–1963 Comp., p. 389; 49 U.S.C. 106(g); 14 CFR 11.69.

§ 71.1 [Amended]

2. The incorporation by reference in 14 CFR 71.1 of the Federal Aviation Administration Order 7400.9D, *Airspace Designations and Reporting Points*, dated September 4, 1996, and effective September 16, 1996, is amended as follows:

Paragraph 6005 Class E Airspace areas extending upward from 700 feet or more above the surface of the earth.

* * * * *

ASW NM E5 Gallup, NM [Revised]

Gallup Municipal Airport, NM
(Lat 35°30′40″N., long 108°47′22″W.)
Gallup VORTAC
(Lat. 35°28′34″N., long 108°52′21″W.)
Gallup ILS Localizer
(Lat 35°30′53″N., long 108°46′28″W.)

That airspace extending upward from 700 feet above the surface within a 6.7-mile radius of Gallup Municipal Airport and within 1.9 miles each side of the Gallup ILS Localizer southwest course extending from the 6.7-mile radius to 12.6 miles southwest of the airport and within 2 miles each side of the 074° bearing from the airport extending from the 6.7-mile radius to 9.1 miles east of the airport and within 1.3 miles each side of the 242° radial of the Gallup VORTAC extending from the 6.7-mile radius to 11.5 miles southwest of the airport and that airspace extending upward from 1,200 feet above the surface within an area bounded by a line beginning at lat 35°47′30″N, long 108°34′02″W; to lat 35°26′50″N, long 108°34′02″W; to lat 35°13′15″N, long 109°06′02″W' to lat 35°20′25″N, long 109°10′42″W; to lat 35°52′00″N, long 108°47′02″W; to point of beginning excluding that airspace within the New Mexico, NM, Class E airspace area.

* * * * *

Issued in Fort Worth, TX, on March 7, 1997.

Albert L. Viselli,

Acting Manager, Air Traffic Division, Southwest Region.

[FR Doc. 97–6529 Filed 3–13–97; 8:45 am]

BILLING CODE 4910–13–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

21 CFR Parts 200, 250, and 310

[Docket No. 96N–0183]

RIN 0910–AA53

Consolidation of Drug Regulations

AGENCY: Food and Drug Administration, HHS.

ACTION: Final rule.

SUMMARY: The Food and Drug Administration (FDA) is consolidating a list of drugs, previously determined by rulemaking to be new drugs, into one section. This document also removes the sections now providing for these drugs, except for certain information in the regulations that FDA considers to be necessary. This action, which will make the regulations more concise and efficient, is being taken in response to the President's regulatory reinvention initiative (REGO).

EFFECTIVE DATE: April 14, 1997.

FOR FURTHER INFORMATION CONTACT: Mary E. Catchings, Food and Drug Administration, Center for Drug Evaluation and Research (HFD–7), 7500 Standish Pl., Rockville, MD 20855, 301–594–2041.

SUPPLEMENTARY INFORMATION:

I. Background

On March 4, 1995, President Clinton issued a memorandum titled ''Regulatory Reinvention Initiative,'' which directed all Federal agencies to conduct a page-by-page review of their existing regulations and to ''eliminate or revise those that are outdated or otherwise in need of reform.'' As a result of that review and as part of its response to the President's directive, FDA published a document in the Federal Register of June 11, 1996 (61 FR 29502), proposing to amend those parts of its drug regulations codified in parts 200, 250, and 310 (21 CFR parts 200, 250, and 310), regarding certain drugs determined by rulemaking to be new drugs.

FDA proposed the following: (1) To revise § 310.502 to consolidate into one section a list of drugs (now codified in parts 200, 250, and 310) that have been determined by rulemaking procedures to be new drugs requiring approved new drug applications, and (2) to remove those sections in parts 200, 250, and 310 now providing for those drugs, except for certain information in § 310.509 that FDA considers to be necessary. The agency received no comments in response to the proposal to amend or remove these regulations.

II. Analysis of Impacts

FDA has examined the impacts of the final rule under Executive Order 12866 and the Regulatory Flexibility Act (5 U.S.C. 601–612). Executive Order 12866 directs agencies to assess all costs and benefits of available regulatory alternatives and, when regulation is necessary, to select regulatory approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity). The agency believes that this final rule is consistent with the regulatory philosophy and principles identified in the Executive Order. In addition, the final rule is not a significant regulatory action as defined by the Executive Order and so is not subject to review under the Executive Order.

The Regulatory Flexibility Act requires agencies to analyze regulatory options that would minimize any significant impact of a rule on small entities. The Commissioner of Food and Drugs certifies that the final rule will not have a significant economic impact on a substantial number of small entities. Therefore, under the Regulatory Flexibility Act, no further analysis is required.

III. Environmental Impact

The agency has determined under 21 CFR 25.24(a)(8) that this action is of a type that does not individually or cumulatively have a significant effect on the human environment. Therefore, neither an environmental assessment nor an environmental impact statement is required.

List of Subjects

21 CFR Part 200

Drugs, Prescription drugs.

21 CFR Part 250

Drugs.

21 CFR Part 310

Administrative practice and procedure, Drugs, Labeling, Medical devices, Reporting and recordkeeping requirements.

Therefore, under the Federal Food, Drug, and Cosmetic Act, the Public Health Service Act, and under authority delegated to the Commissioner of Food and Drugs, 21 CFR parts 200, 250, and 310 are amended as follows:

PART 200—GENERAL

1. The authority citation for 21 CFR part 200 continues to read as follows:

Authority: Secs. 201, 301, 501, 502, 503, 505, 506, 507, 508, 515, 701, 704, 705 of the Federal Food, Drug, and Cosmetic Act (21 U.S.C. 321, 331, 351, 352, 353, 355, 356, 357, 358, 360e, 371, 374, 375).

Subpart B [Removed]

2. Subpart B, consisting of §§ 200.30 and 200.31 is removed and reserved.

PART 250—SPECIAL REQUIREMENTS FOR SPECIFIC HUMAN DRUGS

3. The authority citation for 21 CFR part 250 continues to read as follows:

Authority: Secs. 201, 306, 402, 502, 503, 505, 601(a), 602(a) and (c), 701, 705(b) of the Federal Food, Drug, and Cosmetic Act (21 U.S.C. 321, 336, 342, 352, 353, 355, 361(a), 362(a) and (c), 371, 375(b)).

§ 250.10 [Removed]

4. Section 250.10 *Oral prenatal drugs containing fluorides intended for human use* is removed.

§ 250.103 [Removed]

5. Section 250.103 *Thorium dioxide for drug use* is removed.

§ 250.106 [Removed]

6. Section 250.106 *Cobalt preparations intended for use by man* is removed.

PART 310—NEW DRUGS

7. The authority citation for 21 CFR part 310 continues to read as follows:

Authority: Secs. 201, 301, 501, 502, 503, 505, 506, 507, 512–516, 520, 601(a), 701, 704, 705, 721 of the Federal Food, Drug, and Cosmetic Act (21 U.S.C. 321, 331, 351, 352, 353, 355, 356, 357, 360b–360f, 360j, 361(a), 371, 374, 375, 379e); secs. 215, 301, 302(a), 351, 354–360F of the Public Health Service Act (42 U.S.C. 216, 241, 242(a), 262, 263b–263n).

8. Section 310.502 is revised to read as follows:

§ 310.502 Certain drugs accorded new drug status through rulemaking procedures.

(a) The drugs listed in this paragraph (a) have been determined by rulemaking procedures to be new drugs within the meaning of section 201(p) of the act. Except as provided in paragraph (b) of this section, an approved new drug application under section 505 of the act and part 314 of this chapter is required for marketing the following drugs:

(1) Aerosol drug products for human use containing 1,1,1-trichloroethane.

(2) Aerosol drug products containing zirconium.

(3) Amphetamines (amphetamine, dextroamphetamine, and their salts, and levamfetamine and its salts) for human use.

(4) Camphorated oil drug products.

(5) Certain halogenated salicylanilides (tribromsalan (TBS, 3,4′,5-tribromosalicylanilide), dibromsalan (DBS, 4′, 5-dibromosalicylanilide), metabromsalan (MBS, 3, 5-dibromosalicylanilide), and 3,3′, 4,5′-tetrachlorosalicylanilide (TC–SA)) as an ingredient in drug products.

(6) Chloroform used as an ingredient (active or inactive) in drug products.

(7) Cobalt preparations intended for use by man.

(8) Intrauterine devices for human use for the purpose of contraception that incorporate heavy metals, drugs, or other active substances.

(9) Oral prenatal drugs containing fluorides intended for human use.

(10) Parenteral drug products in plastic containers.

(11) Sterilization of drugs by irradiation.

(12) Sweet spirits of nitre drug products.

(13) Thorium dioxide for drug use.

(14) Timed release dosage forms.

(15) Vinyl chloride as an ingredient, including propellant, in aerosol drug products.

(b) Any drug listed in paragraph (a) of this section, when composed wholly or partly of any antibiotic drug, must be certified under section 507 of the act or exempted from certification under section 507 of the act for marketing.

§ 310.504 [Removed]

9. Section 310.504 *Amphetamines (amphetamine, dextroamphetamine, and their salts and levamfetamine and its salts) for human use* is removed.

§ 310.506 [Removed]

10. Section 310.506 *Use of vinyl chloride as an ingredient, including propellant, of aerosol drug products* is removed.

§ 310.507 [Removed]

11. Section 310.507 *Aerosol drug products for human use containing 1,1,1-trichloroethane* is removed.

§ 310.508 [Removed]

12. Section 310.508 *Use of certain halogenated salicylanilides as an inactive ingredient in drug products* is removed.

13. Section 310.509 is revised to read as follows:

§ 310.509 Parenteral drug products in plastic containers.

(a) Any parenteral drug product packaged in a plastic immediate container is not generally recognized as safe and effective, is a new drug within the meaning of section 201(p) of the act, and requires an approved new drug application as a condition for marketing. An ‘‘Investigational New Drug Application’’ set forth in part 312 of this chapter is required for clinical investigations designed to obtain evidence of safety and effectiveness.

(b) As used in this section, the term ‘‘large volume parenteral drug product’’ means a terminally sterilized aqueous drug product packaged in a single-dose container with a capacity of 100 milliliters or more and intended to be administered or used intravenously in a human.

(c) Until the results of compatibility studies are evaluated, a large volume parenteral drug product for intravenous use in humans that is packaged in a plastic immediate container on or after April 16, 1979, is misbranded unless its labeling contains a warning that includes the following information:

(1) A statement that additives may be incompatible.

(2) A statement that, if additive drugs are introduced into the parenteral system, aseptic techniques should be used and the solution should be thoroughly mixed.

(3) A statement that a solution containing an additive drug should not be stored.

(d) This section does not apply to a biological product licensed under the Public Health Service Act of July 1, 1944 (42 U.S.C. 201).

§ 310.510 [Removed]

14. Section 310.510 *Use of aerosol drug products containing zirconium* is removed.

§ 310.513 [Removed]

15. Section 310.513 *Chloroform, use as an ingredient (active or inactive) in drug products* is removed.

§ 310.525 [Removed]

16. Section 310.525 *Sweet spirits of nitre drug products* is removed.

§ 310.526 [Removed]

17. Section 310.526 *Camphorated oil drug products* is removed.

Dated: March 7, 1997.

William K. Hubbard,

Associate Commissioner for Policy Coordination.

[FR Doc. 97–6411 Filed 3–13–97; 8:45 am]

BILLING CODE 4160–01–F

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21 CFR Part 520

Oral Dosage Form New Animal Drugs; Lufenuron Tablet

AGENCY: Food and Drug Administration, HHS.

ACTION: Final rule.

SUMMARY: The Food and Drug Administration (FDA) is amending the animal drug regulations to reflect approval of a supplemental new animal drug application (NADA) filed by Ciba-Geigy Animal Health, Ciba-Geigy Corp. The supplemental NADA provides for oral administration of lufenuron tablets at a minimum dose of 30 milligrams per kilogram (mg/kg) for the control of flea populations on cats.

EFFECTIVE DATE: March 14, 1997.

FOR FURTHER INFORMATION CONTACT: Marcia K. Larkins, Center for Veterinary Medicine (HFV–112), Food and Drug Administration, 7500 Standish P1., Rockville, MD 20855, 301–594–0614.

SUPPLEMENTARY INFORMATION: Ciba-Geigy Animal Health, Ciba-Geigy Corp., P.O. Box 18300, Greensboro, NC 27419–8300, filed supplemental NADA 141–035, which provides for oral administration of Program® (lufenuron) tablets to cats 6 weeks of age or older. The drug is approved in 90- or 204.9-mg tablets, given once a month, directly or broken and mixed into wet food, for the control of flea populations. Lufenuron has no deleterious effect on adult fleas but it prevents most flea eggs from hatching or maturing into adults. The supplemental NADA is approved as of January 23, 1997, and the regulations are amended in 21 CFR 520.1288 by revising the heading for paragraph (c) and by adding new paragraph (d) to reflect the approval. The basis for approval is discussed in the freedom of information summary.

In accordance with the freedom of information provisions of 21 CFR part 20 and 514.11(e)(2)(ii), a summary of safety and effectiveness data and information submitted to support approval of this application may be seen in the Dockets Management Branch (HFA–305), Food and Drug Administration, 12420 Parklawn Dr., rm. 1–23, Rockville, MD 20857, between 9 a.m. and 4 p.m., Monday through Friday.

Under section 512(c)(2)(F)(iii) of the Federal Food, Drug, and Cosmetic Act (21 U.S.C. 360b(c)(2)(F)(iii)), this approval qualifies for 3 years of marketing exclusivity beginning January 23, 1997, because the application contains substantial evidence of effectiveness of the drug involved, studies of animal safety or, in the case of food-producing animals, human food safety studies (other than bioequivalence or residue studies) required for approval and conducted or sponsored by the applicant.

The agency has determined under 21 CFR 25.24(d)(1)(iii) that this action is of a type that does not individually or cumulatively have a significant effect on the human environment. Therefore, neither an environmental assessment nor an environmental impact statement is required.

List of Subjects in 21 CFR Part 520

Animal drugs.

Therefore, under the Federal Food, Drug, and Cosmetic Act and under authority delegated to the Commissioner of Food and Drugs and redelegated to the Center for Veterinary Medicine, 21 CFR part 520 is amended as follows:

PART 520—ORAL DOSAGE FORM NEW ANIMAL DRUGS

1. The authority citation for 21 CFR part 520 continues to read as follows:

Authority: Sec. 512 of the Federal Food, Drug, and Cosmetic Act (21 U.S.C. 360b).

2. Section 520.1288 is amended by revising the heading for paragraph (c) and by adding new paragraph (d) to read as follows:

§ 520.1288 Lufenuron tablets.

* * * * *

(c) *Conditions of use in dogs*—

* * * * *

(d) *Conditions of use in cats*—(1) *Amount.* 90-milligram tablet for cats up to 6 pounds of body weight, 204.9-milligram tablet for cats 7 to 15 pounds, a combination of tablets for cats over 15 pounds (a minimum of 13.6 milligrams per pound (30 milligrams per kilogram)).

(2) *Indications for use.* For control of flea populations.

(3) *Limitations.* For oral use in cats 6 weeks of age or older, once a month, directly or broken and mixed into wet food. Administer in conjunction with a full meal to ensure adequate absorption. Treat all cats in the household to ensure maximum benefits. Because the drug has no affect on adult fleas, the concurrent use of insecticides that kill adults may be necessary depending on the severity of the infestation.

Dated: February 11, 1997.

Stephen F. Sundlof,

Director, Center for Veterinary Medicine.

[FR Doc. 97–6412 Filed 3–13–97; 8:45 am]

BILLING CODE 4160–01–F

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21 CFR Parts 556 and 558

Animal Drugs, Feeds, and Related Products; Chlortetracycline and Tiamulin

AGENCY: Food and Drug Administration, HHS.

ACTION: Final rule.

SUMMARY: The Food and Drug Administration (FDA) is amending the animal drug regulations to reflect approval of a new animal drug application (NADA) filed by Fermenta Animal Health Co. The NADA provides for the use of separately approved Type A medicated articles containing chlortetracycline and tiamulin in making Type C combination medicated feed. The feed is used in swine for treatment of bacterial enteritis and bacterial pneumonia and for control of swine dysentery. The regulations are also amended to increase the tolerance for tiamulin residue in swine liver.

EFFECTIVE DATE: March 14, 1997

FOR FURTHER INFORMATION CONTACT: George K. Haibel, Center for Veterinary Medicine (HFV–133), Food and Drug Administration, 7500 Standish Pl., Rockville, MD 20855, 301–594–1644.

SUPPLEMENTARY INFORMATION: Fermenta Animal Health Co., 10150 North Executive Hills Blvd., Kansas City, MO 64153–2314, filed NADA 141–011, which provides for using separately approved Type A medicated articles containing chlortetracycline calcium complex equivalent to 50 to 100 grams per pound (g/lb) of chlortetracycline hydrochloride (CTC HCl) and 5 or 10 g/lb of tiamulin in making a Type C medicated swine feed. The feed contains a specific level of each animal drug as follows: Chlortetracycline calcium complex equivalent to approximately 400 g of CTC HCl per ton (g/t), varying with body weight and feed consumption to provide 10 milligrams of chlortetracycline/lb of body weight daily, and tiamulin (as tiamulin hydrogen fumarate) 35 g/t. The feed is indicated for use in swine for treatment of swine bacterial enteritis and bacterial pneumonia caused by certain bacteria susceptible to CTC and for control of swine dysentery caused by certain bacteria susceptible to tiamulin. The NADA is approved as of August 20, 1996, and the regulations are amended in §§ 558.128 and 558.600 (21 CFR 558.128 and 558.600) to reflect the approval. The basis for approval is discussed in the freedom of information summary.

These are new animal drugs used in Type A medicated articles to make Type B and C medicated feeds. Chlortetracycline and tiamulin are Category I drugs, which as provided in 21 CFR 558.4, do not require a licensed feed mill for making a Type B or C medicated feed from a Type A medicated article. Therefore, a licensed feed mill is not required for making a Type B or C medicated feed containing chlortetracycline in combination with tiamulin as in the approved subject NADA and in amended § 558.600.

Additionally, the safe concentrations and tolerances for tiamulin and chlortetracycline have been revised based on the new food consumption factors described in FDA's document entitled ''General Principles for Evaluating the Safety of Compounds Used in Food-Producing Animals'' (59 FR 37499, July 22, 1994). The revised tolerances for chlortetracycline were published in the Federal Register of December 23, 1996. The revised safe concentrations for total residues of tiamulin in edible swine tissues are 5 parts per million (ppm) in muscle, 15 ppm in liver, and 30 ppm in kidney and fat. These new safe concentrations for tiamulin residues in edible tissues correspond to a revised tolerance for tiamulin of 0.6 ppm for 8-*alpha*-hydroxymutilin (marker compound) in swine liver (target tissue). Accordingly, 21 CFR 556.738 is revised to increase the tolerance for the marker compound from 0.4 to 0.6 ppm.

The sponsor has demonstrated via residue depletion studies, using approved regulatory methods, that the depletion characteristics of the marker residues for each drug in the combination are not significantly modified and that the existing regulatory method for each drug in the combination is not interfered with by residues of the other drug. Therefore, the Center for Veterinary Medicine (CVM) concludes that the composition of each drug's residue is unchanged while in the combination. Accordingly, CVM is establishing a pre-slaughter withdrawal period of 2 days for use of this combination.

In accordance with the freedom of information provisions of 21 CFR part 20 and 21 CFR 514.11(e)(2)(ii), a summary of safety and effectiveness data and information submitted to support approval of this application may be seen in the Dockets Management Branch (HFA–305), Food and Drug Administration, 12420 Parklawn Dr., rm. 1–23, Rockville, MD 20857, between 9 a.m. and 4 p.m., Monday through Friday.

Under section 512(c)(2)(F)(ii) of the Federal Food, Drug, and Cosmetic Act (21 U.S.C. 360b(c)(2)(F)(ii)), this approval qualifies for a 3-year period of marketing exclusivity beginning on August 20, 1996, because new clinical or field investigations (other than bioequivalence or residue studies), or human food safety studies (other than bioequivalence or residue studies) essential to the approval were conducted or sponsored by the applicant.

The agency has determined under 21 CFR 25.24(d)(1)(ii) that this action is of a type that does not individually or cumulatively have a significant effect on the human environment. Therefore, neither an environmental assessment nor an environmental impact statement is required.

List of Subjects

21 CFR Part 556

Animal drugs, Foods.

21 CFR Part 558

Animal drugs, Animal feeds.

Therefore, under the Federal Food, Drug, and Cosmetic Act and under authority delegated to the Commissioner of Food and Drugs and redelegated to the Center for Veterinary Medicine, 21 CFR parts 556 and 558 are amended as follows:

PART 556—TOLERANCES FOR RESIDUES OF NEW ANIMAL DRUGS IN FOOD

1. The authority citation for 21 CFR part 556 continues to read as follows:

Authority: Secs. 402, 512, 701 of the Federal Food, Drug, and Cosmetic Act (21 U.S.C. 342, 360b, 371).

2. Section 556.738 is revised to read as follows:

§ 556.738 Tiamulin.

A tolerance of 0.6 part per million is established for 8-*alpha*-hydroxymutilin (marker compound) in liver (target tissue) of swine.

PART 558—NEW ANIMAL DRUGS FOR USE IN ANIMAL FEEDS

3. The authority citation for 21 CFR part 558 continues to read as follows:

Authority: Secs. 512, 701 of the Federal Food, Drug, and Cosmetic Act (21 U.S.C. 360b, 371).

4. Section 558.128 is amended by adding new paragraph (c)(3)(xiii) to read as follows:

§ 558.128 Chlortetracycline.

* * * * *

(c) * * *

(3) * * *

(xiii) Tiamulin in accordance with § 558.600.

5. Section 558.600 is amended by adding new paragraph (c)(4) to read as follows:

§ 558.600 Tiamulin.

* * * * *

(c) * * *

(4) *Amount per ton*. 35 grams of tiamulin (as tiamulin hydrogen fumarate), plus the equivalent of approximately 400 grams of chlortetracycline hydrochloride varying with body weight and feed consumption to provide 10 milligrams of chlortetracycline per pound of body weight daily.

(i) *Indications for use*. Treatment of swine bacterial enteritis caused by *Escherichia coli* and *Salmonella choleraesuis* and bacterial pneumonia caused by *Pasteurella multocida* susceptible to chlortetracycline, and control of swine dysentery associated with *Serpulina (Treponema) hyodysenteriae* susceptible to tiamulin.

(ii) *Limitations*. Feed continuously as sole ration for 14 days. Not for use in swine weighing over 250 pounds. Use as only source of chlortetracycline and tiamulin. Swine being treated with tiamulin should not have access to feeds containing polyether ionophores (e.g., monensin, salinomycin, narasin, semduramicin, and lasalocid) as adverse reactions may occur. If signs of toxicity occur, discontinue use. Withdraw 2 days before slaughter. As chlortetracycline calcium complex, Type A medicated articles containing the equivalent of 50 to 100 grams per pound of chlortetracycline hydrochloride provided by 000004 and 046573 in § 510.600(c) of this chapter.

Dated: February 6, 1997.

Stephen F. Sundlof,

Director, Center for Veterinary Medicine.

[FR Doc. 97–6476 Filed 3–13–97; 8:45 am]

BILLING CODE 4160–01–F

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21 CFR Part 812

[Docket No. 92N–0308]

Investigational Device Exemptions; Disqualification of Clinical Investigators

AGENCY: Food and Drug Administration, HHS.

ACTION: Final rule.

SUMMARY: The Food and Drug Administration (FDA) is amending its medical device regulations to include provisions for the disqualification of clinical investigators. These amended regulations parallel, with minor exceptions, the regulations for disqualification of clinical investigators of drugs, biologics, and animal drugs. The agency is finalizing this regulation to further implement its plan for consistent bioresearch monitoring procedures for all products regulated by FDA and to improve the remedies available to deal with clinical investigators who violate the law. This action is being taken under the Medical Device Amendments of 1976.

DATES: Effective May 13, 1997.

FOR FURTHER INFORMATION CONTACT: Rodney T. Allnutt, Center for Devices and Radiological Health (HFZ–310), Food and Drug Administration, 2094 Gaither Rd., Rockville, MD 20850, 301–594–4718.

SUPPLEMENTARY INFORMATION:

I. Background

FDA has long intended to have clinical investigator disqualification procedures available for medical device investigations. Although the investigational device exemption (IDE) regulation part 812 (21 CFR part 812) allows FDA to initiate regulatory action against a study sponsor due to a noncompliant investigator, such as terminating the sponsor's IDE or imposing additional restrictions under the IDE, the IDE regulation did not expressly provide for clinical investigator disqualification. The proposed IDE regulation, published in the Federal Register of August 20, 1976 (41 FR 35282 at 35311), contained disqualification provisions for clinical investigators in proposed § 812.119 that were not included in the final IDE regulations published on January 18, 1980 (45 FR 3732), which apply to device investigations generally. Disqualification provisions were included, however, in part 813 (21 CFR part 813) on investigational exemptions for intraocular lenses (IOL's) in § 813.119 (42 FR 58874, November 11, 1977). The preamble to the final IDE regulation, published in the Federal Register of January 18, 1980 (45 FR 3732 at 3749), noted that proposed § 812.119 was being removed and would be addressed in FDA's final agency-wide regulation on the obligations of clinical investigators, which had been proposed in the Federal Register of August 8, 1978 (43 FR 35186). This agency-wide regulation, however, was never finalized.

In the Federal Register of October 6, 1993 (58 FR 52142), FDA issued a proposed rule to remove part 813, the regulation on investigational exemptions for IOL's. FDA received two comments in response to the proposed rule. These comments were addressed in the preamble to the rule that removed part 813, which was published in the Federal Register of January 29, 1997 62 FR 4164.

In the Federal Register of October 6, 1993 (58 FR 52144), FDA also published a proposed rule governing disqualification of clinical investigators of medical devices, to be added to part 812. The proposed rule was virtually identical to the regulation for disqualification of clinical investigators of IOL's, which would be removed with the proposed removal of part 813. In the proposed rule, however, FDA expressly invited comments on whether the procedures for disqualification of clinical investigators of medical devices should be identical, or virtually identical to the regulation for the disqualification of clinical investigators of drugs and biologics in § 312.70 (21 CFR 312.70). FDA stated that if comments persuaded the agency to revise the proposed rule to follow § 312.70 precisely or closely, the agency might issue a final rule which parallels § 312.70.

FDA received three comments stating an explicit preference for rules governing disqualification of investigators of drugs as specified in § 312.70, over the rules that had been proposed for disqualification of investigators of devices. Two other comments that did not specifically mention § 312.70 nevertheless suggested changes to the proposed rule that would make it more consistent with the drug investigator disqualification rule. The other three comments FDA received did not address this issue.

Two comments preferred § 312.70 to the proposed regulation because § 312.70 does not contain the perceived flaws found in the proposed regulation. These comments stated, e.g., that the threshold for disqualification in § 312.70 is set much higher and the terms are more clearly defined than in the proposed regulation. One of these comments requested that the Center for Devices and Radiological Health (CDRH) adopt § 312.70 in its entirety because of the perceived flaws in the proposed rule. That comment also noted that most medical device companies and investigators of devices are unfamiliar with § 312.70. Therefore, the comment recommended that FDA propose a rule similar to § 312.70 and give interested parties a chance to comment on the reproposal. The third comment stated that the regulation for disqualification of investigators of investigational new drugs is a better model because it is a relatively simple and clear regulation, it does not impose unfair and potentially harmful presumptions, and it would give FDA the immediate consistency it desires among product lines.

FDA has been persuaded by the comments that the regulation governing disqualification of investigators of medical devices should parallel the regulation for disqualification of investigators of drugs and biologics in § 312.70 (as well as the regulation for disqualification of investigators of animal drugs at § 511.1(c) (21 CFR 511.1(c))). This rule for disqualification of investigators of medical devices, therefore, adopts regulations that are basically the same as those governing disqualification of investigators of drugs, biologics, and animal drugs, with minor exceptions.

The agency has concluded, however, that a reproposal is unnecessary because the agency received sufficient and adequate comments to make a reasoned determination about the final rule and because the agency provided clear notice to interested persons that a final regulation paralleling § 312.70 would be adopted if the comments persuaded the agency that this approach represented the best option. (See the Federal Register of October 6, 1993, that stated ''FDA is giving notice that, if comments persuade the agency to revise the proposed rule to follow § 312.70 * * * the agency may issue a rule that parallels § 312.70.''(58 FR 52144).)

In response to the concern that medical device companies and investigators of medical devices are unfamiliar with § 312.70, the agency notes that this rule is consistent with FDA's regulatory program for investigators of drugs, which has existed for more than 30 years, and that interested persons were provided explicit notice in the proposal that the same disqualification procedures might be adopted for investigators of devices. Interested parties who may be unfamiliar with FDA's bioresearch monitoring activities for clinical investigations may find useful the description of the agency's investigator disqualification process that is provided in an FDA publication entitled ''Food and Drug Administration INFORMATION SHEETS for Institutional Review Boards and Clinical Investigators'' (October 1995 revision), which is currently available from the Office of the Associate Commissioner for Health Affairs.

This document explains why FDA was persuaded by the comments to adopt the approach being codified and also describes the ways in which the rule has been modified from the proposal in order to incorporate the changes suggested by the comments. In addition, this document identifies comments that are now moot because the agency adopted disqualification procedures that parallel § 312.70. Finally, this document also explains FDA's basis for not including other suggestions.

II. Summary of the Final Rule

The final rule consists of the following provisions:

A. Grounds for Disqualification

Section 812.119(a) establishes that disqualification proceedings will only begin if FDA has information indicating that the investigator has: (1) Repeatedly or deliberately failed to comply with the requirements of this part, part 50 (21 CFR part 50), or part 56 (21 CFR part 56); or (2) repeatedly or deliberately submitted false information either to the sponsor of the investigation or in any required report.

B. Informal Conference or Written Explanation and Opportunity for a Hearing on Proposed Disqualification

In accordance with § 812.119(a), when FDA determines that one of the grounds for disqualification may exist, CDRH will furnish the investigator written notice of the matter under complaint and offer the investigator an opportunity to explain the matter in writing, or, at the option of the investigator, in an informal conference. If an explanation is offered and accepted by CDRH, the disqualification process will be terminated. If an explanation is offered but not accepted by CDRH, the investigator will be given an opportunity for a regulatory hearing under part 16 (21 CFR part 16) on the question of whether the investigator is entitled to continue to receive investigational devices.

C. Notification of Disqualification

In accordance with § 812.119(b), after evaluating all available information, including any explanation presented by the investigator, if the Commissioner of Food and Drugs (the Commissioner) determines that the investigator has repeatedly or deliberately failed to comply with the requirements of this part, part 50, or part 56, or has repeatedly or deliberately submitted false information either to the sponsor of the investigation or in any required report, the Commissioner will notify the investigator, the sponsor of any investigation in which the investigator has been named as a participant, and the reviewing Institutional Review Board (IRB), that the investigator is not entitled to receive investigational devices. The notification will provide a statement of the basis for such determination.

D. Actions Upon Disqualification

Under § 812.119(c), FDA shall examine each IDE and each cleared or approved application submitted under subpart E of part 807 (21 CFR part 807) or part 814 (21 CFR part 814), containing data reported by an investigator who has been determined to be ineligible to receive investigational devices to determine whether the investigator has submitted unreliable data that are essential to the continuation of the investigation or essential to the clearance/approval of any marketing application.

Under § 812.119(d), if the Commissioner determines, after the unreliable data submitted by the investigator are eliminated from consideration, that the data remaining are inadequate to support a conclusion that it is reasonably safe to continue the investigation, the Commissioner will notify the sponsor, who shall have an opportunity for a regulatory hearing under part 16. If a danger to the public health exists, however, the Commissioner shall order withdrawal of approval of the IDE before any hearing. In such case, the sponsor shall have an opportunity for a regulatory hearing under part 16 on the question of whether the IDE should be reinstated. (See § 812.30(c)(2).)

In accordance with § 812.119(e), if the Commissioner determines, after the unreliable data submitted by the investigator are eliminated from consideration, that the continued clearance or approval of the marketing application for which the data were submitted cannot be justified, the Commissioner will proceed to withdraw approval or rescind clearance of the medical device in accordance with the applicable provisions of the act and the agency's regulations.

E. Reinstatement of a Disqualified Investigator

Under § 812.119(f), a disqualified investigator may be reinstated when the Commissioner determines that the investigator has presented adequate assurances, through written submissions, that the investigator will employ investigational devices solely in compliance with the provisions of parts 812, 50, and 56.

F. Scope

The final rule clarifies that the provisions for disqualification of investigators of devices apply to all cleared or approved and pending device applications containing or relying upon any clinical investigations performed by the disqualified investigator. Such applications include IDE's, premarket notifications (510(k)'s), and premarket approval applications (PMA's). Subsequent to publication of the proposed rule, FDA discovered that 510(k)'s were inadvertently omitted from proposed § 812.119(a). Because the provisions for disqualification of a clinical investigators are intended to apply to all device applications containing or relying upon any clinical investigations performed by the disqualified investigator, this final rule clarifies that such provisions apply to 510(k)'s, IDE's, and PMA's.

The final rule also clarifies that no clinical investigator of medical devices is exempt from the disqualification regulations. The exemptions and abbreviated requirements described in part 812 for certain investigations are intended to relate to those procedures and requirements under part 812 associated with submitting an IDE application or obtaining an IDE prior to conducting an investigation. Section 812.2 is not intended to eliminate the responsibility of clinical investigators of devices to abide by procedures and standards associated with good scientific practice. Whether or not an investigation requires an IDE, every clinical investigator whose work may be considered in connection with a marketing application is expected to comply with the agency's regulations and scientific standards relating to informed consent, IRB oversight, inspections, adherence to investigational protocols, and pertinent reports and recordkeeping. The final rule amends § 812.2 to clarify that the provisions governing disqualification of investigators apply to all clinical investigations of devices, including those that do not require FDA approval of an IDE, e.g., clinical investigations involving nonsignificant risk devices, and those categories of exempted devices identified in the IDE regulation.

III. Identification and Explanation for the Differences Between the Regulation for Disqualification of Investigators of Devices and the Regulation for Investigators of Drugs and Biologics

Section 812.119(a) establishes that FDA may begin the disqualification process ''if FDA has information indicating that an investigator has repeatedly or deliberately submitted false information either to the sponsor of the investigation or in any required report.'' This language is somewhat different from the parallel provision for investigators of drugs and biologics (§ 312.70(a)), which states that a disqualification process may begin when there is information that the investigator ''has submitted to the sponsor false information in any required report.'' (The parallel regulation for investigators of animal drugs (§ 511.1(c)), requires FDA to have information indicating that the investigator ''has submitted false information either to the sponsor of the investigation or in any required report.'') FDA believes that the language in the final rule for disqualification of investigators of devices more clearly states the intent of both the drug and animal drug provisions.

As discussed in section IV. of this document, several comments raised concern that investigators would be unfairly penalized for submitting false information inadvertently or when it was beyond their individual control. The agency does not intend isolated or inadvertent failures to be the basis for disqualification and the addition of the phrase ''repeatedly or deliberately'' clarifies that the agency's threshold for taking action against a clinical investigator requires the submission of false information to be either deliberate or frequent enough to call into question the individual's eligibility to continue the investigation.

Section 812.119(b) establishes that, in addition to notifying the investigator and the sponsor of any investigation in which a disqualified investigator has been named as a participant (§ 312.70(b)), FDA will also notify the reviewing IRB of a final disqualification determination. FDA has made this addition in response to several comments received on the proposed rule and after concluding that this notification will better enable the reviewing IRB to meet an obligation for continuing review to ensure the protection of the rights and well-being of the subject.

Section 812.119(d) establishes that in addition to notifying the sponsor of any investigation (§ 312.70(d)), FDA will also notify the reviewing IRB that the Commissioner has determined that a danger to public health exists and has ordered withdrawal of approval of the IDE. FDA has considered the comments received on the proposed rule that prompted the adoption of notification of IRB's as provided under § 812.119(a), and has concluded that this notification will better enable IRB's to monitor an investigation that is ordered terminated to ensure continued protection of the rights and well-being of the subject.

FDA believes that these changes improve the medical device regulations for disqualification of clinical investigators without creating significant discrepancies between those procedures and the regulations that are now in place for clinical investigators of drugs, biologics, and animal drugs. FDA intends to consider making similar changes to § 312.70 in order to make the investigator disqualification regulations as consistent as possible.

IV. Comments

FDA published a proposed rule to revise its medical device regulations to include provisions for the disqualification of clinical investigators (58 FR 52144). Because of an inadvertent error, the date for submission of comments was incorrectly published as November 5, 1993, even though the preamble to the proposed rule provided an opportunity for interested persons to submit comments on the proposed rule until December 6, 1993. A correction notice was published in the Federal Register of October 14, 1993 (58 FR 53245). Subsequently, in the Federal Register of December 6, 1993 (58 FR 64209), FDA extended the comment period for the proposed rule from December 6, 1993, until January 5, 1994, in response to a request for an extension from a trade association.

The agency received a total of eight comments from trade associations, manufacturers, law offices, a medical device consultant, a medical center, and FDA's Center for Drug Evaluation and Research (CDER). A summary of the comments and the agency's response to them is provided below:

A. Secondary Studies; Proposed § 812.119(a)(2)

1. A comment suggested that the proposed provisions authorizing disqualification of secondary studies, i.e., clinical studies by the same investigator other than the one in which misconduct is shown, should be limited. The comment recommended that limits should be placed on retrospective disqualification of secondary studies because FDA has authority to monitor the integrity and performance of secondary studies. For instance, FDA has the opportunity to inspect clinical study sites, to review sponsor's monitoring of studies, and to analyze the results of studies. Because the agency already has the authority to monitor the integrity and performance of secondary studies, the comment requested FDA to establish the following provisions relating to disqualification of secondary studies: (1) Secondary studies should be disqualified only when there is specific, demonstrable basis for a charge of misconduct; (2) the burden of proof relative to disqualification of a secondary study should be with FDA; (3) sponsors of secondary studies should be notified of disqualification of investigators; and (4) the basis for disqualification of a secondary study should be limited to issues which represent ongoing threats to the safety of current or future users of the product.

Another comment suggested that proposed § 812.119(a)(2) should not apply to other ongoing IDE's in which the investigator is involved, unless particular information establishes that a potential problem exists with respect to that specific clinical investigation.

The agency agrees with these comments and is persuaded that the approach set forth in § 312.70 and now being adopted in part 812 is preferable to the proposal because it addresses these concerns. The final rule does not automatically disqualify all IDE's or secondary studies. Instead, § 812.119 establishes that FDA will examine each IDE to determine whether the disqualified investigator has submitted unreliable data that are essential to the continuation of any investigation in which the investigator has been named a participant. (See § 812.119(c).) If the Commissioner determines, after the unreliable data submitted by the investigator are eliminated from consideration, that the data remaining are inadequate to support a conclusion that it is reasonably safe to continue the investigation, the Commissioner will notify the sponsor, who shall have an opportunity for a regulatory hearing under part 16. (See § 812.119(d).)

Thus, in accordance with § 812.119(c) and (d), FDA may terminate ''secondary'' clinical investigations in which the disqualified investigator has been involved only after FDA: (1) Has determined that the disqualified investigator has submitted unreliable data that are essential to the continuation of any investigation in which the investigator has been named a participant; (2) eliminates the unreliable data from consideration and determines that the data remaining are inadequate to support a conclusion that it is reasonably safe to continue the investigation; and (3) provides the sponsor with an opportunity for a regulatory hearing.

In accordance with § 812.119(d), the initial burden of proof relative to disqualification of secondary studies/ IDE's rests with the agency. If FDA's initial determination is that the data remaining are inadequate to support a conclusion that it is reasonably safe to continue the investigation, the sponsor will be provided with an opportunity to challenge FDA's findings during a regulatory hearing.

The comment's suggestion that sponsors of secondary studies be notified of the disqualification of investigators has already been incorporated into § 812.119(b), which requires, among other things, notification of the sponsor of any clinical investigation in which the disqualified investigator has been named as a participant.

B. Proposed § 812.119(a)

2. One comment requested that § 812.119(a), which was drafted to apply to the disqualification of an investigator ''who has failed to comply with any'' of the regulations applicable to clinical investigators, be changed to apply only to investigators who have engaged in serious violations.

The agency agrees with the basic concern raised by this comment and believes that the decision to adopt a final regulation that parallels § 312.70 has addressed this concern. Section 812.119(a) replaces ''has failed to comply with any of the regulations set forth in this part'' with ''has repeatedly or deliberately failed to comply with the requirements of this part, part 50, or part 56 * * *.'' An investigator's failure to repeatedly or deliberately comply with the requirements of this part, part 50, or part 56 constitutes a serious violation.

C. Proposed § 812.119(a)(1)

3. One comment noted that the use of the term ''necessarily'' in proposed § 812.119(a)(1) implies that a disqualification decision may or may not constitute a finding or recommendation that the investigator is not qualified to practice or teach medicine or should be subject to other sanctions by third parties. The comment suggested that these areas are outside the disqualification proceeding purview. As a result, the word ''necessarily'' should be omitted from § 812.119(a)(1) to ensure that a disqualification decision would not affect these areas of the investigator's life.

Proposed § 812.119(a)(1) has not been adopted in the final regulation. However, under § 812.119(b), the disqualification notification issued by the agency constitutes only a finding that the investigator is not entitled to receive investigational devices and a statement of the basis for a determination by the agency that the investigator is disqualified from participation in clinical investigations. The agency's disqualification does not constitute any other finding.

D. Proposed § 812.119(b)(1)

4. Proposed § 812.119(b)(1) provided that an investigator could be disqualified if he or she ''caused false information to be submitted'' to FDA or a sponsor. According to one comment, this language allows an investigator to be held responsible even if the investigator were unaware that the information was false. The comment said that this provision fails to recognize that all clinical studies have some degree of unavoidable error. Another comment stated that an investigator should not be disqualified because he or she submitted false information generated by a third person, unless the investigator knew of the falsehood. A third comment requested that proposed § 812.119(b)(1) be rewritten as follows: An investigator should be disqualified if ''the investigator deliberately caused false information to be submitted to FDA or to the sponsor of a study with the understanding that information may be submitted to FDA.''

It is not FDA's intention to disqualify an investigator for a single submission of false data for which the investigator was not responsible. The agency would not seek to disqualify investigators under such circumstances and FDA believes that the adoption of § 812.119(a) ensures against such situations.

In accordance with § 812.119(a), an investigator may be disqualified ''If FDA has information indicating that an investigator has * * * deliberately or repeatedly submitted false information either to the sponsor of the investigation or in any required report, * * *.'' Requiring submission of false information to be ''deliberately'' submitted ensures that investigators will not be held responsible for a single submission of false information if the investigator were unaware that the information was false.

Although the ''repeated submission of false information'' basis for disqualification does not ensure that an investigator will not be disqualified for the submission of false information if the investigator were unaware that the information was false, FDA believes that such a basis for disqualification is necessary. A clinical investigator who repeatedly causes false information to be submitted to FDA, whether through carelessness or mismanagement, jeopardizes the integrity of the study and safety of the patients. The agency believes that investigators who repeatedly submit false information should be disqualified from participation in such investigations.

E. Proposed § 812.119(b)(3)

5. Five comments suggested modifying the language in proposed § 812.119(b)(3) in order to clarify the grounds for disqualification and to afford clinical investigators and FDA a less severe remedy than disqualification for less serious violations. One comment recommended that FDA incorporate the standard used in § 312.70, which states that investigators may be disqualified for repeated or deliberate failures to comply with regulations.

The final rule addresses the concerns raised by these comments by adopting § 812.119(a), which parallels, with minor modifications, § 312.70(a). Section § 812.119(a) states that clinical investigators may be disqualified only under the following situations: (1) Repeated or deliberate failure to comply with the requirements of parts 812, 50, or 56; or (2) repeated or deliberate submission of false information either to the sponsor of the investigation or in any required report.

The agency believes that the concern regarding affording clinical investigators a remedy other than disqualification for less serious violations has also been addressed in § 812.119(a). Section 812.119(a) provides the investigator with an opportunity to explain the matter in writing, or in an informal conference with the center. FDA believes that this opportunity is the appropriate time for a clinical investigator to dispute or explain any of the allegations cited in the written notice proposing disqualification. Based on the explanation given, CDRH may determine that the investigator's disqualification is not necessary and terminate the proceeding. The clinical investigator also may decide to enter into a consent agreement with the agency that terminates the disqualification proceeding.

F. Proposed § 812.119(c) and (d)

6.A comment requested that, in addition to the investigator receiving written notice, the sponsor of the clinical investigation, as well as IRB, should be informed about any written notice by FDA to the clinical investigator of an allegation involving noncompliance with regulations that may be grounds to justify disqualification of the investigator. Another comment requested that FDA be required to notify the sponsor, IRB, and other sponsors who are employing or have previously employed the investigator to conduct clinical studies requiring prior FDA review, that a potential problem exists at the same time FDA notifies the investigator about the opportunity for a written explanation, an informal conference, or a hearing. The comment contended that giving such notification will allow the sponsors to take actions to minimize the potential effect of disqualification.

One comment suggested adding the following provision to § 812.119(c):

The written notice to the investigator will be copied to the sponsor of the investigation, as well as the IRB reviewing the investigation. Sponsors of other clinical studies requiring prior FDA review which are being or have been conducted by the investigator will also be notified. FDA will issue this notice to the IRB and sponsors within 15 working days after the notice is issued to the clinical investigator.

Furthermore, it was requested that the disqualification process termination notice to the clinical investigator, provided for in § 812.119(c)(2), be required to be copied to the sponsor of the investigation, the IRB reviewing the investigation, and sponsors of other clinical studies requiring prior FDA review which are being or have been conducted by the investigator.

The agency does not believe that additional notification of preliminary findings should be required routinely as part of the investigation of an investigator who may be disqualified because further investigation may determine the investigator to be in compliance with the relevant regulations, and also because sponsors and IRB's have access to Form FD–483 and warning letters relating to their clinical investigators. The agency does recognize, however, that there are times when it is reasonable or necessary for FDA to notify the sponsor of a study and the reviewing IRB prior to a final disqualification determination in order to ensure the integrity of a study or the rights and well-being of a subject. While there are circumstances that may warrant early notification to sponsors or IRB's, this final regulation, like its counterparts for investigators of drugs, biologics, and animal drugs, does not explicitly address this issue. However, separate from this rulemaking, the agency is establishing a working group, representing all FDA centers, to establish a uniform policy on the issue of prior disclosure to sponsors and IRB's.

The agency has adopted § 812.119(b), which parallels the language used in § 312.70(b) of the investigational new drug (IND) regulations for disqualification of investigators, and provides that ''any sponsor of an investigation in which the investigator has been named as a participant and the reviewing IRB'' shall be notified of the agency's final decision on the disqualification of the investigator and the basis for the disqualification. The agency has also adopted § 812.119(d), which parallels the language used in § 312.70(d) of the IND regulations, and provides that sponsors and IRB's shall be notified and sponsors given an opportunity for a hearing, when FDA intends to withdraw approval for an IDE, or if a danger to public health warrants immediate termination of an investigation, that the Commissioner shall order the immediate withdrawal of approval of the IDE and the sponsor shall be offered an opportunity for a hearing on whether the IDE should be reinstated.

G. Proposed § 812.119(c)(1) and (d)

7. A comment suggested that the written notice in § 812.119(c)(1) and (d) should describe the noncompliance with sufficient detail and particularity so that the investigator is informed fully of the alleged violation. An investigator cannot provide an informed response unless sufficient detail is provided.

The agency agrees with the concern expressed by this comment and has adopted § 812.119(a), which establishes the agency's responsibility to provide adequate details. Section 812.119(a) provides that ''* * * the Center for Devices and Radiological Health will furnish the investigator written notice of the matter under complaint * * *.'' FDA intends that such notices include a full description of the alleged violation(s) that are the basis for disqualification.

H. Proposed § 812.119(c)(2)

8. Proposed § 812.119(c)(2) provides for the termination of the proceeding if the investigator offers an explanation for the noncompliance that is accepted by FDA. One comment suggested that § 812.119(c)(2) be rewritten to allow for the termination of the proceeding if the investigator demonstrates that no regulatory violations actually occurred. Another comment recommended that the term ''alleged'' be placed before the word noncompliance in § 812.119(c)(2) to indicate that a noncompliance determination has not been made at this preliminary stage.

The agency believes that these modifications are unnecessary with the adoption of the final rule. In accordance with § 812.119(a), when FDA furnishes the investigator with a written notice of the matter under complaint, FDA will also offer the investigator an opportunity to explain the matter in writing, or at the option of the investigator, at an informal conference. If an explanation is offered by the investigator and accepted by CDRH, the disqualification process will be terminated. The scope of an investigator's explanation is not limited and may include a showing that no regulatory violations actually occurred.

The agency also believes that modifying § 812.119(a) by inserting the term ''alleged'' in the regulatory text is unnecessary because § 812.119(a), unlike proposed § 812.119(c)(2), does not indicate that a final noncompliance determination will be made at this preliminary stage.

I. Proposed § 812.119(c)(2) and (c)(3)

9. A comment requested that the terms ''FDA'' and ''agency'' in § 812.119(c)(2) and (c)(3) be replaced with ''Center for Devices and Radiological Health,'' in order to clarify that informal conferences would not be held at the Commissioner's level.

The concern raised by this comment has been addressed with the adoption of § 812.119(a), which references CDRH, FDA. Also, FDA is taking this opportunity to notify interested persons that CDRH's Division of Compliance Operations has been eliminated through reorganization. The informal conferences will be held by the Division of Bioresearch Monitoring, Office of Compliance, CDRH.

J. Proposed § 812.119(d)

10. A comment stated that the text of proposed § 812.119(d) failed to mention that an opportunity for a hearing exists for an investigator who has received a proposed notice of disqualification.

This concern also has been addressed with the adoption of § 812.119(a). Section 812.119(a) specifically states, ''If an explanation is offered but not accepted by the Center for Devices and Radiological Health, the investigator will be given an opportunity for a regulatory hearing under part 16 * * *.''

K. Proposed § 812.119(f)(1)

11. Under § 812.119(a) and paragraph (f)(1) as proposed, a hearing on the disqualification of an investigator shall be conducted in accordance with the requirements for a regulatory hearing as set forth in part 16. One comment maintained that conducting a regulatory hearing under part 16 does not adequately protect the investigator's due process rights. The comment requested FDA to follow the procedures set forth in part 12 (21 CFR part 12) for a formal evidentiary public hearing when determining whether an investigator should be disqualified.

The agency disagrees with the comment that a part 16 regulatory hearing does not provide adequate due process. A part 16 regulatory hearing is initiated by a notice of opportunity for hearing from FDA. This notice specifies, among other things, the facts and the action that are the subject of the hearing and states the time in which a hearing may be requested. In accordance with part 16, if a hearing is requested, the Commissioner will designate a presiding officer, and the hearing will take place at a time and location agreed upon by the party requesting the hearing, FDA, and the presiding officer. A part 16 regulatory hearing, therefore, adequately protects an investigator's due process rights by providing the investigator with notice and an opportunity to be heard. Moreover, FDA has had extensive experience in the use of part 16 hearings for disqualification proceedings of clinical investigators of new drugs under part 312. FDA's experience has established that part 16 hearings are appropriate in these circumstances and protect the investigator's due process rights. Finally, a part 16 regulatory hearing is more streamlined than a part 12 evidentiary public hearing and will provide a quicker resolution of issues for both FDA and the investigator.

L. Proposed § 812.119(f)(3)

12. Section 812.119(f)(2) provides that a final order disqualifying a clinical investigator will be copied to the sponsor of each clinical investigation subject to requirements for prior submission to FDA that was or is being conducted by the investigator. A comment suggested adding a similar provision to § 812.119(f)(3) so that sponsors will be notified of any final order terminating the disqualification proceeding. Additionally, the comment suggested that FDA provide a copy of such orders to IRB's as well.

The agency has adopted § 812.119(b), which provides for notification of the interested parties after the Commissioner has made a final determination that an investigator is disqualified. After a final disqualification decision has been made, the investigator, the sponsors of any investigations in which the investigator was named as a participant, and the reviewing IRB shall be notified that the investigator is disqualified.

The agency's response to comments concerning notification of interested parties prior to a final disqualification decision has been provided previously. (See the response to comment 6 in section IV.F. of this document.)

M. Proposed § 812.119(g)

13. One comment said that proposed § 812.119(g), actions upon disqualification, may be interpreted to mean that the Commissioner is authorized to make decisions that directly affect the rights and responsibilities of sponsors even though sponsors may not be aware of the disqualification process or be given the opportunity to participate in the disqualification decisions. Another comment maintained that this section may violate sponsors' due process rights. The comment recommended that sponsors be given the opportunity to present their views before the agency takes any of the actions described in proposed § 812.119(g).

The agency has addressed these concerns with the adoption of § 812.119(d), which provides sponsors with the opportunity to participate in proceedings regarding termination of clinical investigations. Under this section, if the Commissioner determines, after the unreliable data submitted by the disqualified investigator are eliminated from consideration, that the data remaining are inadequate to support a conclusion that it is reasonably safe to continue the investigation, the Commissioner will notify the sponsor, who shall have an opportunity for a regulatory hearing under part 16. If a danger to the public health exists, however, the Commissioner shall terminate the clinical investigation immediately and notify the sponsor of that determination. In such case, the sponsor shall have an opportunity for a regulatory hearing under part 16 on the question of whether the clinical investigation should be reinstated.

The agency's adoption of § 812.119(e), which parallels § 312 .70(e), also addresses the concerns about sponsors' rights raised by these comments. This new section provides that if the Commissioner determines, after the unreliable data submitted by the disqualified investigator are eliminated from consideration, that the continued clearance or approval of the device for which the data were submitted cannot be justified, the Commissioner will proceed to rescind clearance or withdraw approval of the marketing application in accordance with the applicable provisions of the act and regulations. These provisions provide adequate due process protections to the sponsor whose clinical investigations are subject to termination and/or whose marketing applications are subject to rescission of clearance or withdrawal of approval following disqualification of clinical investigators.

N. Proposed § 812.119(g)(2)

14. A comment suggested that proposed § 812.119(g)(2) was overly broad because it would allow FDA to terminate an entire study based on the disqualification of a single investigator.

The agency believes that the concern raised by this comment has been addressed with the adoption of § 812.119(d), which, like § 312.70(d), provides a sponsor with notification that the Commissioner has determined that the data are inadequate to support a conclusion that it is reasonably safe to continue the investigation, and an opportunity for a hearing under part 16, as indicated previously. (See the response to comment 13 in section IV.M. of this document.)

15. A comment suggested that there was an inconsistency between proposed § 812.119(g)(2) and proposed § 812.119(b). The comment stated that, under § 812.119(b), the Commissioner must base a disqualification order upon findings that address only limited factual issues. In contrast, § 812.119(g)(2) directed FDA to consider information that goes beyond the scope of the administrative record created during the disqualification proceedings. For example, nothing in proposed § 812.119(b) related to ''the risks of the

subjects from suspension of the study,'' and yet FDA, under § 812.119(g)(2), would consider that factor. The comment recommended that this inconsistency be rectified.

The agency believes that the inconsistency indicated by this comment has been addressed with the adoption of § 812.119(b), which parallels § 312.70(b) and by the elimination of proposed § 812.119(g) in the final rule. Under § 812.119(b), a disqualification decision will be based upon the Commissioner's determination that the investigator has repeatedly or deliberately failed to comply with the requirements of this part, part 50 or part 56, or has deliberately or repeatedly submitted false information either to the sponsor or in any required report, after evaluating all available information, including any explanation presented by the investigator.

O. Proposed § 812.119(g)(2)(i)

16. One comment stated that the meaning of the phrase ''another investigator accepts responsibility for the clinical investigation'' was unclear in this proposed section.

Proposed § 812.119(g)(2)(i) was not adopted in the final rule, thus eliminating any need for clarification indicated by this comment. However, FDA believes that if continuation of an investigation is warranted after an investigator is disqualified, the sponsor of the investigation is responsible for selecting a qualified investigator who shall be responsible for the continuation of the investigation at that site. (See, also, the response to comment 18 in section IV.P. of this document.)

17. A comment expressed concern that proposed § 812.119(g)(2)(i) could be interpreted as broad FDA authority to suspend or terminate an entire clinical investigation, rather than the portion of the investigation conducted by the disqualified investigator. In order for the regulation to be explicit on this issue, this comment suggested that the phrase ''under control of the disqualified investigator'' should be added after ''clinical investigation.'' Additionally, another comment requested that ''clinical investigation'' should be defined as that part of an investigation directly under the control of the disqualified investigator. Furthermore, the comment asked FDA to add the following sentence to this section for clarity: ''Disqualification of an investigator or termination of a clinical investigation under control of a disqualified investigator shall not affect any investigation not under control of the disqualified investigator.''

The agency has previously addressed other comments concerning the termination of an entire investigation or other investigations conducted by the disqualified investigator. (See the responses to comments 1 and 14 in sections IV.A. and N. of this document.)

P. Proposed § 812.119(g)(2)(iii)

18. One comment stated that it is inappropriate for a disqualified investigator to continue monitoring subjects. Instead, this comment recommended that another investigator be appointed to monitor the subject, or the subject should be withdrawn from the study.

The agency agrees that it is inappropriate for a disqualified investigator to continue monitoring clinical trial subjects who are either continuing to receive the test device or are in the followup phase of the trial. An investigator who is disqualified from eligibility to receive investigational devices is disqualified from participation in conducting investigations, including monitoring the subjects of investigations. Therefore, § 812.119(b) provides that once the Commissioner makes a final disqualification determination, the Commissioner will notify the sponsor of any investigation in which the investigator has been named as a participant and the reviewing IRB that the investigator is disqualified. Furthermore, the agency believes that if subjects are currently enrolled or receiving followup visits at the disqualified investigator's site, the sponsor is responsible for selecting, as soon as possible, a qualified investigator who shall be responsible at the site for completing the investigation, including subject followup.

Q. Proposed § 812.119(g)(2)(v)

19. One comment stated that proposed § 812.119(g)(2)(v) was too restrictive. Various comments suggested that § 812.119(g)(2)(v) be expanded to allow continued use if discontinuing use would cause a life-threatening problem, an immediate health problem, or involve significant risks to the person's health.

The agency has not adopted the provision that was the basis for this comment. However, under § 812.119(c) and (d), the Commissioner will determine whether the remaining data are adequate to support a conclusion that it is reasonably safe to continue an investigation, or whether approval should be withdrawn. If there is credible evidence that discontinuing an investigation would cause a life-threatening problem, an immediate health problem, or involve significant risks to the health of a subject, this type of evidence will be considered in support of such determination.

R. Proposed § 812.119(g)(3)

20. Under proposed § 812.119(g)(3), once an investigator is disqualified, FDA would examine approved and pending applications relying on the work of this disqualified investigator. FDA would determine whether the investigation ''is acceptable,'' notwithstanding the disqualification. According to several comments, proposed § 812.119(g)(3) was vague and unfair for various reasons. One comment suggested that FDA incorporate the language used in the IND regulations for disqualification of investigators, which provides that an application will be examined to determine whether the investigator has submitted unreliable data that are ''essential to the continuation of the investigation or essential to the approval of any marketing application.'' (See § 312.70(c).)

The agency agrees with the comments and has adopted § 812.119(c), which parallels the language used in § 312.70(c) of the IND regulations, for disqualification of investigators.

21. Another comment said that the wording,

> Any investigation done by an investigator before or after disqualification may be presumed to be unacceptable, and the person relying on the investigation may be required to establish that the clinical investigation was not affected by the circumstances which led to disqualification of the investigator, * * *.

has many flaws. First, the terminology ''any investigation done by an investigator before or after disqualification may be unacceptable'' is too broad. The comment recommended that the regulation state that an investigator's data will not be accepted to support a marketing application only if the evidence shows that the data are unreliable. The sponsor should then be given the opportunity to validate the data if possible, after exclusion of the adversely affected data. The comment also said that a ''presumption'' of invalidity for any investigation done by an investigator before or after disqualification is inappropriate because, under the proposed rule, that presumption would apply to any clinical investigation performed by the investigator.

The agency believes that the concerns expressed by this comment have been minimized with the adoption of a final rule that parallels § 312.70. Under § 812.119(c), each regulatory submission containing data reported by a disqualified investigator will be examined to determine whether the investigator has submitted unreliable data that are essential to the continuation of the investigation or essential to the approval of any marketing application. It is not unreasonable, however, for FDA to presume that other work done by a disqualified investigator should be reviewed. Because this final rule states that a sponsor is entitled to a hearing before any particular investigation or approval is terminated, the opportunity to validate data will be available to sponsors.

22. Another comment stated that the use of the phrase ''the person relying on the investigation may be required to establish that the investigation was not affected,'' improperly shifts the burden of proof to the sponsor; just because an investigator has failed to comply with the regulations in one study does not imply that all other studies are tainted. This comment recommended that, once FDA determines that an investigator has acted improperly, FDA should conduct an investigation to determine whether other clinical investigations conducted by the disqualified investigator are unreliable.

This recommendation is incorporated into the final rule, which parallels § 312.70. Under § 812.119(c), each IDE and each approved marketing application submitted under part 807 or 814 in which the disqualified investigator has been a participant will be examined by FDA. In essence, final § 812.119(c) places on FDA the initial burden of determining whether any unreliable data have been submitted by the disqualified investigator that are essential to the continuation of any other investigation or to the approval or clearance of any marketing application. (See the agency's responses to comments 1, 13, and 14 in sections IV.A., M., and N. of this document.)

23. A comment urged that an approval should not be withdrawn unless there is evidence that the device is unsafe or ineffective. If the device is found to be safe and effective, the device should remain available, regardless of irregularities in the investigation which led to the disqualification of an investigator.

The agency does not intend to withdraw approval or rescind clearance of devices under § 812.119(e) unless the Commissioner determines, after the unreliable data submitted by the investigator are eliminated from consideration, that the continued approval or clearance of the marketing application for which the data were submitted cannot be justified. By its very nature, unreliable data bring into question the safety and effectiveness of the device. If the marketing application contains data, other than the disqualified data, that support substantial equivalence or safety and effectiveness, FDA would have no reason to remove the device from the market. The course of action taken by FDA with respect to that device will be commensurate with the results of the agency's review, and may include withdrawal of approval of a PMA or recision of a 510(k) if that is deemed necessary. Furthermore, as stated in response to comment 13 in section IV. M. of this document, § 812.119(e) parallels § 312.70(e) and provides sponsors with the opportunity to participate in proceedings regarding withdrawal of approval or recession of clearance of a marketing application.

24. A comment suggested that the regulation should include a reasonable time limit in which a sponsor must validate the data used in a study in which an investigator was disqualified.

The agency agrees with this comment. In accordance with § 812.119(d) and (e), when FDA has reviewed the remaining data after the disqualified investigator's data are eliminated and the Commissioner has determined that the remaining data are inadequate to support continued approval or clearance of an investigation or marketing application, the Commissioner will notify the sponsor, who shall have an opportunity for a regulatory hearing under part 16. The sponsor may request a hearing to present to FDA any new or additional factual information which challenges the determination, including any information that validates the disqualified investigator's data or that indicates the remaining data are adequate to support approval or clearance. The time limit for providing such information is governed by the procedures for conducting a regulatory hearing under part 16.

25. Another comment pointed out that § 812.119(d) and (e) requires a sponsor, in certain circumstances, to submit validating information to show that an IDE or PMA containing or relying upon a clinical investigation performed by a disqualified investigator is not adversely affected. This comment suggested that FDA should offer the sponsor periodic opportunities, i.e., quarterly, monthly, etc., to present validating information for any potentially adversely affected clinical investigation through segregated analysis, adding additional sites, or verification of existing data. According to this comment, offering such periodic opportunities to validate existing data would allow the sponsor to salvage portions of valid data without having to gather clinical data through new investigations.

The agency agrees that such an opportunity may be appropriate. As part of FDA's examination under final § 812.119(c) to determine whether the disqualified investigator has submitted unreliable data that are essential to the continuation of an investigation or essential to the approval of any marketing application, FDA may request that sponsors submit to the agency, on a periodic basis, validating information for a potentially adversely affected clinical investigation or marketing application. Sponsors will receive written notification of such a request.

S. Proposed § 812.119(g)(4)

26. Under proposed § 812.119(g)(4), the determination that a clinical investigation may not be considered in support of an application would not relieve the applicant of any obligation under the statute to submit the results of the clinical investigation to FDA. A comment urged that an applicant should not be required to submit the results of the clinical investigation to FDA because, once a determination has been made that the clinical investigation will not be considered in support of an application, the usefulness of the clinical investigation is questionable.

The agency disagrees with this comment. Although the final rule no longer includes this explicit provision, it is imperative for FDA to review all available information collected on the investigational device, particularly information that may affect the rights, safety, or welfare of the subjects enrolled. Therefore, regardless of whether the clinical data will be used to support a marketing application, the reporting requirements described in other parts of the IDE regulation, e.g., §§ 812.40 and 812.150, must be maintained to provide adequate protection for subjects.

T. Proposed § 812.119(h)(1)

27. Proposed § 812.119(h)(1) would have required the notice of disqualification to state that the results of any investigations conducted by the investigator may not be considered by FDA in support of any IDE or PMA. According to one comment, proposed § 812.119(h)(1) would not permit validating information to be presented by a sponsor to save the IDE or PMA. Because of this, the comment requested that the contents of the disqualification notice not automatically reflect a determination that the study results are not to be considered in support of an IDE or PMA. Instead, the comment

requested that the contents of the disqualification notice state that the results will be evaluated by FDA to determine the effect of disqualification, if any, on the IDE or PMA.

Proposed § 812.119(h)(1), which is addressed in this comment, has not been adopted. However, under § 812.119(b), a disqualification notice is provided that states that the investigator is disqualified and the basis for such determination. Final § 812.119(c), (d), and (e) establish that FDA will review any IDE's, 510(k)'s or PMA's that contain data submitted by the disqualified investigator. If the agency finds that a withdrawal of approval is warranted, the sponsor of the application will be notified and offered an opportunity for a hearing under part 16. The sponsor may request a part 16 hearing to provide relevant information, such as validating information, which may influence a final decision.

28. Under proposed § 812.119(h)(1), upon issuance of a final order disqualifying an investigator or upon entry of a consent decree, FDA would have discretion to notify all or any interested persons. A comment recommended that it be a mandatory requirement that sponsors receive notice of an investigator disqualification both when FDA issues a final order and when FDA has reason to believe that an investigator may be subject to disqualification. Another respondent asked FDA to include in the regulation a provision requiring the notification of the sponsor by FDA when a consent agreement is executed, with a copy of the consent agreement included in the sponsor's notification. Three other respondents suggested that FDA, upon disqualification of a clinical investigator, inform the approving IRB that the investigator has been disqualified.

Proposed § 812.119(h)(1), which is addressed by these comments, has not been adopted in the final rule. However, FDA agrees with these comments in general and has adopted final § 812.119(b), which parallels § 312.70(b). This final rule provides that FDA will give notification of disqualification to the investigator who is disqualified, the sponsor of any investigation in which the investigator has been named a participant, and the reviewing IRB.

The agency's response to comments concerning notification of interested parties prior to a final disqualification decision has been provided previously. (See response to comment 6 in section IV.F. of this document.) Records relating to disqualification proceedings, such as inspectional findings, disqualification determinations, administrative records of determinations and hearings, consent agreements, and reinstatement determinations are disclosable to the public upon request, subject to the provisions of part 20 (21 CFR part 20).

U. Proposed § 812.119(h)(3)

29. According to a comment, proposed § 812.119(h)(3) would not give sponsors notice that an investigator is facing disqualification proceedings. This comment requested that the regulation be revised to require FDA to notify the sponsor if one of its investigators may be facing disqualification.

A similar comment suggested the following wording:

> Whenever FDA has reason to believe that an investigator may be subject to disqualification, the agency will so notify the sponsor of the clinical investigation in question, as well as the sponsor of each clinical investigation subject to requirement of prior submission to FDA that was or is being conducted by the investigator, and the IRB's under which the investigation(s) were conducted. This notification shall occur simultaneously with the agency's notice to the investigator describing the noncompliance and request for an explanation of the noncompliance under paragraph (c) of this section.

Proposed § 812.112(h)(3) addressed in these two comments has not been adopted in the final rule. However, the agency's response to similar comments concerning notification of interested parties prior to a final disqualification decision has been provided previously. (See response to comment 6 in section IV.F. of this document.)

V. Proposed § 812.119(j)

30. This proposed section would have required sponsors to notify FDA any time an investigator is removed from further participation in a clinical investigation. One comment stated that there is no need to require a sponsor to notify FDA when an investigator is removed from a study for nonregulatory reasons. Another comment maintained that requiring sponsors to report a termination, for whatever reasons, could inhibit sponsors from terminating investigators because of the reporting requirements.

Proposed § 812.119(j) addressed in these two comments has not been adopted in the final rule. However, § 812.40 of the existing IDE regulation currently requires sponsors to inform the agency of significant new information about an investigation, including any changes in or terminations of clinical investigators.

W. Publication of a List

31. A comment requested that disqualified investigators be added to a single list maintained by CDER or the Office of Health Affairs in FDA so that IRB's and sponsors are not required to search two (or more) separate lists.

Although the proposed rule did not specifically state that CDRH would maintain a list of clinical investigators who have been disqualified under this authority, FDA intends to compile such a list. This list will be combined with CDER's and the Center for Biologics Evaluation and Research's (CBER's) list of disqualified investigators. The newly combined disqualified clinical investigator list will be maintained by FDA's Office of Regulatory Affairs. This list is disclosable to the public under part 20. A request for the list should be sent in writing to the Freedom of Information Staff (HFZ–35), Food and Drug Administration, 5600 Fishers Lane, rm. 12A–16, Rockville, MD 20857.

V. Environmental Impact

The agency has determined under 21 CFR 25.24(a)(8) that this action is of a type that does not individually or cumulatively have a significant effect on the human environment. Therefore, neither an environmental assessment nor an environmental impact statement is required.

VI. Analysis of Impacts

FDA has examined the impacts of the final rule under Executive Order 12866 and the Regulatory Flexibility Act (5 U.S.C. 601–612). Executive Order 12866 directs agencies to assess all costs and benefits of available regulatory alternatives and, when regulation is necessary, to select regulatory approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity). The agency believes that this final rule is consistent with the regulatory philosophy and principles identified in the Executive Order. In addition, the final rule is not a significant regulatory action as defined by the Executive Order and so is not subject to review under the Executive Order.

The Regulatory Flexibility Act requires agencies to analyze regulatory options that would minimize any significant impact of a rule on small entities. Because the final rule specifies the procedures to be followed for investigator disqualification, the rule does not impose any burden on regulated industry. Procedures themselves are protections and do not impose significant costs beyond what the underlying statute imposes. Thus, the agency certifies that the final rule will not have a significant economic impact on a substantial number of small entities. Therefore, under the Regulatory Flexibility Act, no further analysis is required.

Lists of Subjects in 21 CFR Part 812

Health records, Medical devices, Medical research, Reporting and recordkeeping requirements.

Therefore, under the Federal Food, Drug, and Cosmetic Act and under authority delegated to the Commissioner of Food and Drugs, 21 CFR part 812 is amended as follows:

PART 812—INVESTIGATIONAL DEVICE EXEMPTIONS

1. The authority citation for 21 CFR part 812 continues to read as follows:

Authority: Secs. 301, 501, 502, 503, 505, 506, 507, 510, 513–516, 518–520, 701, 702, 704, 721, 801 of the Federal Food, Drug, and Cosmetic Act (21 U.S.C. 331, 351, 352, 353, 355, 356, 357, 360, 360c–360f, 360h–360j, 371, 372, 374, 379e, 381); secs. 215, 301, 351, 354–360F of the Public Health Service Act (42 U.S.C. 216, 241, 262, 263b–263n).

2. Section 812.2 is amended by revising the introductory text of paragraph (c) to read as follows:

§ 812.2 Applicability.

* * * * *

(c) *Exempted investigations.* This part, with the exception of § 812.119, does not apply to investigations of the following categories of devices: * * *

* * * * *

3. New § 812.119 is added to subpart E to read as follows:

§ 812.119 Disqualification of a clinical investigator.

(a) If FDA has information indicating that an investigator has repeatedly or deliberately failed to comply with the requirements of this part, part 50, or part 56 of this chapter, or has repeatedly or deliberately submitted false information either to the sponsor of the investigation or in any required report, the Center for Devices and Radiological Health will furnish the investigator written notice of the matter under complaint and offer the investigator an opportunity to explain the matter in writing, or, at the option of the investigator, in an informal conference. If an explanation is offered and accepted by the Center for Devices and Radiological Health, the disqualification process will be terminated. If an explanation is offered but not accepted by the Center for Devices and Radiological Health, the investigator will be given an opportunity for a regulatory hearing under part 16 of this chapter on the question of whether the investigator is entitled to receive investigational devices.

(b) After evaluating all available information, including any explanation presented by the investigator, if the Commissioner determines that the investigator has repeatedly or deliberately failed to comply with the requirements of this part, part 50, or part 56 of this chapter, or has deliberately or repeatedly submitted false information either to the sponsor of the investigation or in any required report, the Commissioner will notify the investigator, the sponsor of any investigation in which the investigator has been named as a participant, and the reviewing IRB that the investigator is not entitled to receive investigational devices. The notification will provide a statement of basis for such determination.

(c) Each investigational device exemption (IDE) and each cleared or approved application submitted under this part, subpart E of part 807 of this chapter, or part 814 of this chapter containing data reported by an investigator who has been determined to be ineligible to receive investigational devices will be examined to determine whether the investigator has submitted unreliable data that are essential to the continuation of the investigation or essential to the approval or clearance of any marketing application.

(d) If the Commissioner determines, after the unreliable data submitted by the investigator are eliminated from consideration, that the data remaining are inadequate to support a conclusion that it is reasonably safe to continue the investigation, the Commissioner will notify the sponsor who shall have an opportunity for a regulatory hearing under part 16 of this chapter. If a danger to the public health exists, however, the Commissioner shall terminate the IDE immediately and notify the sponsor and the reviewing IRB of the determination. In such case, the sponsor shall have an opportunity for a regulatory hearing before FDA under part 16 of this chapter on the question of whether the IDE should be reinstated.

(e) If the Commissioner determines, after the unreliable data submitted by the investigator are eliminated from consideration, that the continued clearance or approval of the marketing application for which the data were submitted cannot be justified, the Commissioner will proceed to withdraw approval or rescind clearance of the medical device in accordance with the applicable provisions of the act.

(f) An investigator who has been determined to be ineligible to receive investigational devices may be reinstated as eligible when the Commissioner determines that the investigator has presented adequate assurances that the investigator will employ investigational devices solely in compliance with the provisions of this part and of parts 50 and 56 of this chapter.

Dated: March 3, 1997.

William B. Schultz,

Deputy Commissioner for Policy.

[FR Doc. 97–6475 Filed 3–13–97; 8:45 am]

BILLING CODE 4160–01–F

DEPARTMENT OF THE TREASURY

Internal Revenue Service

26 CFR Part 1

[TD 8560; TD 8597; TD 8660]

RIN 1545–AQ69; 1545–AT58; 1545–AT51

Consolidated Returns; Consolidated and Controlled Groups; Correction

AGENCY: Internal Revenue Service, Treasury.

ACTION: Correcting amendments.

SUMMARY: This document contains technical corrections to final regulations [TD 8560; TD 8597; TD 8660] which were published in the Federal Register on Monday, August 15, 1994 (59 FR 41666); Tuesday, July 18, 1995 (60 FR 36671); and Thursday, March 14, 1996 (61 FR 10447); respectively. The final regulations amend the consolidated return investment adjustment provisions, intercompany transaction provisions and the provisions limiting losses and deductions from transactions between members of a nonconsolidated controlled group.

DATES: The correcting amendments affecting §§ 1.267(f)–1, 1.1502–13(f)(2)(ii), (g)(5), (l)(1), 1.1502–20, 1.1502–32(b), and 1.1502–80(b) are effective July 18, 1995. The correcting amendments affecting §§ 1.1502–11, 1.1502–19, 1.1502–32(f), 1.1502–43, 1.1502–76 and 1.1502–80(d)(1) are effective January 1, 1995. The correcting amendments affecting § 1.1502–13(f)(6) are effective March 14, 1996. For dates of applicability see §§ 1.267(f)–1(l), § 1.1502–11(b)(5), 1.1502–13(l)(1), 1.1502–13(f)(6)(v), 1.1502–19(h), 1.1502–32(h), 1.1502–76(b)(5), 1.1502–80(d), and other relevant provisions.

FOR FURTHER INFORMATION CONTACT: William Barry of the Office of Assistant

Chief Counsel (Corporate), (202) 622–7770 (not a toll-free number).

SUPPLEMENTARY INFORMATION:

Background

The final regulations that are the subject of these correcting amendments are under sections 267 and 1502 of the Internal Revenue Code.

Need for Correction

As published, the final regulations contain errors and omissions which may prove to be misleading and are in need of clarification.

List of Subjects in 26 CFR Part 1

Income taxes, Reporting and recordkeeping requirements.

Accordingly, 26 CFR Part 1 is corrected by making the following correcting amendments:

PART 1—INCOME TAXES

Paragraph 1. The authority citation for Part 1 continues to read in part as follows:

Authority: 26 U.S.C. 7805 * * *

Par. 2. Section 1.267(f)–1 is amended as follows:

1. In paragraph (c)(1)(iii), the first sentence is revised.

2. Paragraph (l)(2) is revised.

The revisions read as follows:

§ 1.267(f)–1 Controlled groups.

* * * * *

(c) * * * (1) * * *

(iii) * * * To the extent S's loss or deduction from an intercompany sale of property is taken into account under this section as a result of B's transfer of the property to a nonmember that is a person related to any member, immediately after the transfer, under sections 267(b) or 707(b), or as a result of S or B becoming a nonmember that is related to any member under section 267(b), the loss or deduction is taken into account but allowed only to the extent of any income or gain taken into account as a result of the transfer. * * *

* * * * *

(l) * * *

(2) *Avoidance transactions.* This paragraph (l)(2) applies if a transaction is engaged in or structured on or after April 8, 1994, with a principal purpose to avoid the rules of this section (and instead to apply prior law). If this paragraph (l)(2) applies, appropriate adjustments must be made in years beginning on or after July 12, 1995, to prevent the avoidance, duplication, omission, or elimination of any item (or tax liability), or any other inconsistency with the rules of this section.

* * * * *

Par. 3. Section 1.1502–11 is amended by revising paragraph (b)(2)(iii), *Example 3.* (e) to read as follows:

§ 1.1502–11 Consolidated taxable income.

* * * * *

(b) * * *

(2) * * *

(iii) * * *

Example 3. * * *

(e) Under paragraph (b)(2)(ii) of this section, S's $30 of loss limited under this paragraph (b) is treated as a separate net operating loss.

* * * * *

Par. 4. Section 1.1502–13 is amended as follows:

1. In paragraph (f)(2)(ii), a sentence is added before the last sentence of the paragraph.

2. In paragraph (f)(6) introductory text, the last sentence is revised.

3. In paragraph (g)(5), *Example 5.* (c), the tenth sentence is revised.

4. In paragraph (l)(1) the third, fourth, and fifth sentences are revised.

The addition and revisions read as follows:

§ 1.1502–13 Intercompany transactions.

* * * * *

(f) * * *

(2) * * *

(ii) * * * B's dividend received deduction under section 243(a)(3) is determined without regard to any intercompany distributions under this paragraph (f)(2) to the extent they are not included in gross income. * * *

* * * * *

(6) * * * For this purpose, P stock is any stock of the common parent held (directly or indirectly) by another member or any stock of a member (the issuer) that was the common parent if the stock was held (directly or indirectly) by another member while the issuer was the common parent.

* * * * *

(g) * * *

(5) * * *

Example 5. * * *

(c) * * * Under § 1.446–3(f), the deemed $100 up front payment by M1 to M2 is taken into account over the term of the new contract in a manner reflecting the economic substance of the contract (for example, allocating the payment in accordance with the forward rates of a series of cash-settled forward contracts that reflect the specified index and the $1,000 notional principal amount). * * *

* * * * *

(l) * * * (1) * * * For example, S's and B's items from S's sale of property to B which occurs in a consolidated return year beginning before July 12, 1995, are taken into account under prior law, even though B may dispose of the property in a consolidated return year beginning on or after July 12, 1995. Similarly, an intercompany distribution to which a shareholder becomes entitled in a consolidated return year beginning before July 12, 1995, but which is distributed in a consolidated return year beginning on or after that date is taken into account under prior law (generally when distributed), because this section generally takes dividends into account when the shareholder becomes entitled to them but this section does not apply at that time. If application of prior law to S's deferred gain or loss from a deferred intercompany transaction (as defined under prior law) occurring in a consolidated return year beginning prior to July 12, 1995, would be affected by an intercompany transaction (as defined under this section) occurring in a consolidated return year beginning on or after July 12, 1995, S's deferred gain or loss continues to be taken into account as provided under prior law, and the items from the subsequent intercompany transaction are taken into account under this section. * * *

* * * * *

Par. 5. Section 1.1502–19 is amended as follows:

1. In paragraph (c)(1)(iii)(A), the last sentence is revised.

2. Paragraph (g) is amended by:

a. Revising the first sentence of the introductory text.

b. Revising the fourth and fifth sentences in *Example 1.* (d).

c. Revising the first sentence in *Example 4.* (b).

d. Revising the first sentence in *Example 6.* (b).

The revisions read as follows:

§ 1.1502–19 Excess loss accounts.

* * * * *

(c) * * *

(1) * * *

(iii) * * *

(A) * * * An asset of S is not considered to be disposed of or abandoned to the extent the disposition is in complete liquidation of S or is in exchange for consideration (other than relief from indebtedness);

* * * * *

(g) *Examples.* For purposes of the examples in this section, unless otherwise stated, P owns all 100 shares of the only class of S's stock and S owns all 100 shares of the only class of T's stock, the stock is owned for the entire year, T owns no stock of lower-tier members, the tax year of all persons is the calendar year, all persons use the accrual method of accounting, the facts set forth the only corporate activity, all transactions are between unrelated persons, and tax liabilities are disregarded. * * *

Example 1. * * *

(d) * * * Under section 301(d), P's basis in the T stock is $60. Under § 1.1502–13, and paragraph (b)(2) of this section, S's $160 gain from the distribution is deferred and taken into account in Year 5 as a result of P's sale of the T stock. * * *

* * * * *

Example 4. * * *

(b) *Analysis.* Under paragraph (c)(2) of this section, S is treated as disposing of each of its shares of T's stock immediately before T becomes a nonmember. * * *

* * * * *

Example 6. * * *

(b) *Analysis.* Under paragraph (c)(1)(iii)(A) of this section, P's excess loss account on each of its shares of S's stock ordinarily is taken into account at the time substantially all of S's assets are treated as disposed of, abandoned, or destroyed for Federal income tax purposes. * * *

* * * * *

Par. 6. Section 1.1502–20 is amended as follows:

1. In paragraph (b)(6), *Example 5.* (iii) is revised.

2. In paragraph (e)(3), *Example 1.* (i), the third sentence is revised.

3. In paragraph (e)(3), *Example 1.* (ii) is revised.

The revisions read as follows:

§ 1.1502–20 Disposition or deconsolidation of subsidiary stock.

* * * * *

(b) * * *

(6) * * *

Example 5. * * *

(iii) T's issuance of additional shares to the public results in S's intercompany loss being taken into account under the acceleration rule of § 1.1502–13(d) because there is no difference between P's $100 basis in the T stock and the $100 basis the T stock would have had if P and S had been divisions of a single corporation. S's loss taken into account is disallowed under paragraph (a)(1) of this section.

* * * * *

(e) * * *

(3) * * *

Example 1. * * * (i) * * * With the view described in paragraph (e)(1) of this section, P transfers land with a value of $100 and a basis of $100 to T in exchange for preferred stock with a $200 redemption price and liquidation preference. * * *

(ii) Under section 305, the redemption premium is treated as a distribution of property to which section 301 and § 1.1502–13(f)(2) apply. Under §§ 1.1502–13 and 1.1502–32, P's aggregate basis in the preferred and common stock is unaffected by the deemed distributions.

* * * * *

Par. 7. Section 1.1502–32 is amended as follows:

1. In paragraph (b)(3)(ii)(A), the second sentence is revised.

2. In paragraph (b)(3)(v), the last sentence is revised.

3. In paragraph (b)(5)(ii), *Example 5.* (c), the second sentence is revised.

4. In paragraph (b)(5), *Example 6.* (b) is revised.

5. In paragraph (f), a sentence is added after the second sentence.

The addition and revisions read as follows:

§ 1.1502–32 Investment adjustments.

* * * * *

(b) * * *

(3) * * *

(ii) * * * (A) * * * For example, S's dividend income to which § 1.1502–13(f)(2)(ii) applies, and its interest excluded from gross income under section 103, are treated as tax-exempt income. * * *

* * * * *

(v) * * * See § 1.1502–13(f)(2)(iv) for taking into account distributions to which section 301 applies (but not other distributions treated as dividends) under the entitlement rule.

* * * * *

(5) * * *

(ii) * * *

Example 5. * * *

(c) * * * Under § 1.1502–13(f)(2)(iv), S is treated as making a $70 distribution to P at the time P becomes entitled to the distribution. * * *

Example 6. * * *

(b) *Analysis.* Under section 358, P's basis in the S stock is increased by its basis in the T stock. Under § 1.1502–13(f)(3) the money received is treated as being taken into account immediately after the transaction. Thus, the $10 is treated as a dividend distribution under section 301 and under paragraph (b)(3)(v) of this section, the $10 is a distribution to which paragraph (b)(2)(iv) of this section applies. Accordingly, P's basis in the S stock is $160 immediately after the merger, which is then decreased by the $10 distribution taken into account immediately after the transaction, resulting in a basis of $150.

* * * * *

(f) * * * For example, if T merges into S, S is treated, as the context may require, as a successor to T and as becoming a member of the group. * * *

* * * * *

Par. 8. Section 1.1502–43 is amended by revising paragraph (a)(3)(iii) to read as follows:

§ 1.1502–43 Consolidated accumulated earnings tax.

(a) * * *

(3) * * *

(iii) Earnings and profits resulting from the disposition of a member's stock are determined without regard to the stock basis adjustments under §§ 1.1502–32 and 1.1502–33(c)(1).

* * * * *

Par. 9. Section 1.1502–76 is amended by revising paragraph (b)(4), *Example 1.* (a) and the first sentence of *Example 1.* (c) to read as follows:

§ 1.1502–76 Taxable year of members of group.

* * * * *

(b) * * *

(4) * * *

Example 1. Items allocated between consolidated and separate returns. (a) *Facts.* P and S are the only members of the P group. P sells all of S's stock to individual A on June 30, and therefore S becomes a nonmember on July 1 of Year 2.

* * * * *

(c) *Acquisition of another subsidiary before end of tax year.* The facts are the same as in paragraph (a) of this *Example 1,* except that on July 31 P acquires all the stock of T (which filed a separate return for its year ending on November 30 of Year 1) and T therefore becomes a member on August 1 of Year 2. * * *

* * * * *

Par. 10. Section 1.1502–80 is amended as follows:

1. Paragraph (b) is revised.

2. In paragraph (d)(1), a sentence is added to the end of the paragraph.

The addition and revision reads as follows:

§ 1.1502–80 Applicability of other provisions of law.

* * * * *

(b) *Non-applicability of section 304.* Section 304 does not apply to any acquisition of stock of a corporation in an intercompany transaction or to any intercompany item from such transaction occurring on or after July 24, 1991.

* * * * *

(d) * * * (1) * * * For purposes of this paragraph (d), any reference to a transferor or transferee includes, as the context may require, a reference to a successor or predecessor.

* * * * *

Cynthia E. Grigsby,

Chief, Regulations Unit, Assistant Chief Counsel (Corporate).

[FR Doc. 97–6068 Filed 3–13–97; 8:45 am]

BILLING CODE 4830–01–P

PENSION BENEFIT GUARANTY CORPORATION

29 CFR Part 4044

Allocation of Assets in Single-Employer Plans; Interest Assumptions for Valuing Benefits

AGENCY: Pension Benefit Guaranty Corporation.

ACTION: Final rule.

SUMMARY: The Pension Benefit Guaranty Corporation's regulation on Allocation of Assets in Single-Employer Plans prescribes interest assumptions for valuing benefits under terminating single-employer plans. This final rule amends the regulation to adopt interest assumptions for plans with valuation dates in April 1997.

EFFECTIVE DATE: April 1, 1997.

FOR FURTHER INFORMATION CONTACT: Harold J. Ashner, Assistant General Counsel, Office of the General Counsel, Pension Benefit Guaranty Corporation, 1200 K Street, NW., Washington, DC 20005, 202–326–4024 (202–326–4179 for TTY and TDD).

SUPPLEMENTARY INFORMATION: The PBGC's regulation on Allocation of Assets in Single-Employer Plans (29 CFR part 4044) prescribes actuarial assumptions for valuing plan benefits of terminating single-employer plans covered by title IV of the Employee Retirement Income Security Act of 1974.

Among the actuarial assumptions prescribed in part 4044 are interest assumptions. These interest assumptions are intended to reflect current conditions in the financial and annuity markets.

Two sets of interest assumptions are prescribed, one set for the valuation of benefits to be paid as annuities and one set for the valuation of benefits to be paid as lump sums. This amendment adds to appendix B to part 4044 the annuity and lump sum interest assumptions for valuing benefits in plans with valuation dates during April 1997.

For annuity benefits, the interest assumptions will be 6.10 percent for the first 25 years following the valuation date and 5.00 percent thereafter. The annuity interest assumptions represent a decrease (from those in effect for March 1997) of 0.10 percent for the first 25 years following the valuation date and are otherwise unchanged. For benefits to be paid as lump sums, the interest assumptions to be used by the PBGC will be 4.75 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. The lump sum interest assumptions represent a decrease (from those in effect for March 1997) of 0.25 percent for the period during which a benefit is in pay status and for the seven years directly preceding that period; they are otherwise unchanged.

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, as accurately as possible, current market conditions.

Because of the need to provide immediate guidance for the valuation of benefits in plans with valuation dates during April 1997, 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 in 29 CFR Part 4044

Pension insurance, Pensions.

In consideration of the foregoing, 29 CFR part 4044 is amended as follows:

PART 4044—[AMENDED]

1. The authority citation for part 4044 continues to read as follows:

Authority: 29 U.S.C. 1301(a), 1302(b)(3), 1341, 1344, 1362.

2. In appendix B, a new entry is added to Table I, and Rate Set 42 is added to Table II, as set forth below. The introductory text of each table is republished for the convenience of the reader and remains unchanged.

Appendix B to Part 4044—Interest Rates Used to Value Annuities and Lump Sums

TABLE I.—ANNUITY VALUATIONS

[This table sets forth, for each indicated calendar month, the interest rates (denoted by i_1, i_2, . . . , and referred to generally as i_t) assumed to be in effect between specified anniversaries of a valuation date that occurs within that calendar month; those anniversaries are specified in the columns adjacent to the rates. The last listed rate is assumed to be in effect after the last listed anniversary date.]

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 1997	.0610	1–25	.0500	>25	N/A	N/A

TABLE II.—LUMP SUM VALUATIONS

[In using this table: (1) For benefits for which the participant or beneficiary is entitled to be in pay status on the valuation date, the immediate annuity rate shall apply; (2) For benefits for which the deferral period is y years (where y is an integer and $0 < y \leq n_1$), interest rate i_1 shall apply from the valuation date for a period of y years, and thereafter the immediate annuity rate shall apply; (3) For benefits for which the deferral period is y years (where y is an integer and $n_1 < y \leq n_1 + n_2$), interest rate i_2 shall apply from the valuation date for a period of $y - n_1$ years, interest rate i_1 shall apply for the following n_1 years, and thereafter the immediate annuity rate shall apply; (4) For benefits for which the deferral period is y years (where y is an integer and $y > n_1 + n_2$), interest rate i_3 shall apply from the valuation date for a period of $y - n_1 - n_2$ years, interest rate i_2 shall apply for the following n_2 years, interest rate i_1 shall apply for the following n_1 years, and thereafter the immediate annuity rate shall apply.]

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
* * *	*	*		*			*	
42	04–1–97	05–1–97	4.75	4.00	4.00	4.00	7	8

Issued in Washington, D.C., on this 10th day of March 1997.

John Seal,

Acting Executive Director, Pension Benefit Guaranty Corporation.

[FR Doc. 97–6487 Filed 3–13–97; 8:45 am]

BILLING CODE 7708–01–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 271

[FRL–5691–8]

Oklahoma: Final Authorization of State Hazardous Waste Management Program Revisions

AGENCY: Environmental Protection Agency (EPA).

ACTION: Review of immediate final rule technical corrections.

SUMMARY: The State of Oklahoma has applied for Final authorization to revise its hazardous waste program under the Resource Conservation and Recovery Act (RCRA). The EPA has reviewed Oklahoma's application and decided that its hazardous waste program revision satisfies all of the requirements necessary to qualify for final authorization. As such, EPA published an immediate final rule on October 9, 1996, for 30-day public review and comment period. The EPA did not receive comments by the close of business November 25, 1996. Today's publication is a technical correction to the State Analog chart, listing the State regulations that are equivalent to the Federal rules.

DATES: Effective date: March 14, 1997. This technical correction is in regard to final authorization for Oklahoma which affirms the immediate final decision previously published, and notifies the public that the final authorization was effective on December 23, 1996.

FOR FURTHER INFORMATION CONTACT: Alima Patterson, Authorization Coordinator, Grants and Authorization Section (6PG–G), EPA Region 6, First Interstate Bank Tower at Fountain Place, 1445 Ross Avenue, Dallas, Texas 75202, Phone number: (214) 665–8533.

SUPPLEMENTARY INFORMATION:

A. Technical Corrections

The Oklahoma Department of Environmental Quality (ODEQ) submitted a comment containing technical corrections to the State Analog chart at 61 FR 52884–52886, listing the State regulations that are equivalent to the rules promulgated to the Federal RCRA implementing regulations in 40 CFR parts 124, 260–268, and 270 that were published on October 9, 1996. Many of the dates cited in that chart were incorrect and the following chart lists the correct dates of the State analogs that are being recognized as equivalent to the appropriate Federal requirements. The following chart replaces the previously published chart.

Federal Citation	State analog
1. Requirements for Preparation, Adoption, and Submittal of Implementation Plans, [58 FR 38816] July 20, 1993. (Checklist 125).	Oklahoma Hazardous Waste Management Act (OHWMA), as amended, 27A Oklahoma Statutes (O.S.), Supp. 1994, §§ 2–7–107 (A), (4) and (5), and 2–2–104, effective 1994; and Oklahoma Administrative Code (OAC) Rules 252:200–3–1, 252–200–3–2 through 252:200–3–6, effective July 1, 1995.
2. Testing and Monitoring Activities, [58 FR 46040] August 31, 1993. (Checklist 126)	OHWMA, as amended, 27A O.S., Supp. 1994, §§ 2–2–106, effective 1994, OAC Rules 252:200–3–1 through 252:200–3–6, effective July 1, 1995.
3. Burning of Hazardous Waste in Boilers and Industrial Furnaces, [58 FR 59598] November 9, 1993. (Checklist 127)	OHWMA, as amended, 27A O.S., Supp. 1994, §§ 2–2–104, and 2–7–107(A)(5), effective 1994 and OAC Rules 252:200–3–1 through 252:200–3–6, effective July 1, 1995.
4. Hazardous Waste Management Systems; Identification and Listing of Hazardous Waste; Waste from Wood Surface Protection, [59 FR 458] January 4, 1994. (Checklist 128)	OHWMA, as amended, 27A O.S., Supp. 1994 §§ 2–2–104 and § 2–7–106, effective 1994 and OAC Rules 252:200–3–1 through 252:200–3–6, effective July 1, 1995.
5. Hazardous Waste Management System; Identification and Listing of Hazardous Waste; Treatability Studies Sample Exclusion, [59 FR 8362] February 18, 1994. (Checklist 129)	OHWMA, as amended, 27A O.S., Supp. 1994 §§ 2–2–104 and 2–7–106, effective 1994 and OAC Rules 252:200–3–1 through 252:200–3–6, effective July 1, 1995.
6. Hazardous Waste Management System; Identification and Listing of Hazardous Waste; Recycled Used Oil Management Standards, [59 FR 10550] March 4, 1994. (Checklist 130).	OHWMA, as amended, 27A O.S., Supp. 1994, §§ 2–2–104, and 2–7–107(A)(5) effective 1994, and OAC Rules 252:200–3–1 through 252:200–3–6, effective July 1, 1995.
7. Recordkeeping Instructions, [59 FR 13891] March 24, 1994. (Checklist 131).	OHWMA, as amended, 27A O.S., Supp. 1994, § 2–2–104, and 2–7–105(5), and 2–7–106, effective 1994, and OAC Rules 252:200–3–1 through 252:200–3–6, effective July 1, 1995.
8. Hazardous Waste Management System; Identification and Listing of Hazardous Wastes; Wastes from Wood Surface Protection; Correction, [59 FR 28484] June 2, 1994. (Checklist 132).	OHWMA, as amended, 27A O.S., Supp. 1994 § 2–7–106, and 2–2–104, effective 1994, and OAC Rules 252:200–3–1 through 252:200–3–6, effective July 1, 1995.
9. Standards Applicable to Owners and Operators of Hazardous Waste Treatment, Storage, and Disposal Facilities, Underground Storage, Tanks, and Underground Injection Control Systems; Financial Assurance; Letter of Credit, [59 FR 29958] June 10, 1994. (Checklist 133).	OHWMA, as amended, 27A O.S., Supp. 1994, §§ 2–2–104, effective 1994, and OAC Rules 252:200–3–1 through 252:200–3–6 effective July 1, 1995.
10. Hazardous Waste Management System; Correction of Listing of P015-Beryllium Powder, [59 FR 31551–31552] June 20, 1994. (Checklist 134).	OHWMA, as amended, 27A O.S., Supp. 1994, §§ 2–2–104, and 2–7–106, effective 1994, and OAC Rules 252:200–3–1 through 252:200–3–6, effective July 1, 1995.

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is not a ''significant regulatory action'' and, is therefore not subject to review by the Office of Management and Budget. In addition, this action does not impose any enforceable duty or contain any unfunded mandate as described in the Unfunded Mandates Reform Act of 1995

(Pub. L. 104–4), or require prior consultation with State officials as specified by Executive Order 12875 (58 FR 58093, October 28, 1993), or involve special consideration of environmental justice related issuess as required by Executive Order 12898 (59 FR 7629, February 16, 1994).

Because this action is not subject to notice-and-comment requirements under the Administrative Procedure Act or any other statute, it is not subject to the provisions of the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*).

Under 5 U.S.C. 801(a)(1)(A) as added by the Small Business Regulatory Enforcement Fairness Act of 1996, EPA submitted a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives and the Comptroller General of the General Accounting Office prior to publication of this rule in today's Federal Register. This rule is not a ''major rule'' as defined by 5 U.S.C. 804(2).

Authority: This notice is issued under the authority of Sections 2002(a), 3006 and 7004(b) of the Solid Waste Disposal Act as amended 42 U.S.C. 6912(a), 6926, 6974(b).

Dated: February 11, 1997.

Jerry Clifford,

Acting Regional Administrator.

[FR Doc. 97–6511 Filed 3–13–97; 8:45 am]

BILLING CODE 6560–50–P

LEGAL SERVICES CORPORATION

45 CFR Part 1610

Use of Non-LSC Funds

AGENCY: Legal Services Corporation.

ACTION: Interim rule with request for comments.

SUMMARY: This interim rule revises the Legal Services Corporation's (''Corporation'' or ''LSC'') rule concerning the use of non-LSC funds by LSC recipients. The revisions are intended to address constitutional challenges raised by the previous rule, and to ensure that no LSC-funded entity engages in restricted activities. This revised rule deletes the provisions on transfers of non-LSC funds and adds a new section setting out standards for the integrity of recipient programs.

DATES: The interim rule is effective on March 14, 1997. Comments must be submitted on or before April 14, 1997.

ADDRESSES: Comments should be submitted to the Office of the General Counsel, Legal Services Corporation, 750 First St. NE., 11th Floor, Washington, DC 20002–4250.

FOR FURTHER INFORMATION CONTACT: Victor Fortuno, General Counsel, (202) 336–8910.

SUPPLEMENTARY INFORMATION: On December 2, 1996, the Corporation published a completely revised final rule to implement Section 504 in the Corporation's FY 1996 appropriations act, Pub. L. 104–134, 110 Stat. 1321 (1996), as incorporated by the Corporation's FY 1997 appropriations act, Pub. L. 104–208, 110 Stat. 3009. Section 504 applies certain restrictions to any person or entity receiving LSC funds, effectively restricting the use of virtually all of a recipient's funds to the same degree that it restricts LSC funds. Although not required to by law, the Corporation extended the restrictions on a recipient's funds to a transfer of a recipient's non-LSC funds. Thus, the rule required that when a recipient transferred its non-LSC funds to an entity that had no LSC funds, the conditions would remain attached to the transferred funds. However, the other funds of the entity would not be affected.

In January 1997, five legal services recipients in Hawaii, Alaska, and California, together with two of their program lawyers, two non-federal funders and a client organization, filed suit in the United States District Court for the District of Hawaii challenging a number of the Section 504 restrictions as unconstitutional conditions on their use of non-LSC funds. *Legal Aid Society of Hawaii, et al.* v. *Legal Services Corporation,* Civil Action No. 97–00032 ACK. On February 14, 1997, the Court entered an order which preliminarily enjoined the Corporation from enforcing restrictions on the recipients'' use of non-LSC funds for certain restrictions as to which the Court determined that the plaintiffs'' had a fair likelihood of demonstrating an infringement of First Amendment rights. The Court's preliminary ruling was grounded in pertinent part on its understanding of the Corporation's interrelated organization policy, but also implicated the expansive reach of the Corporation's restrictions on non-LSC funds. The effect of the preliminary order is to allow those recipients who are plaintiffs in the case to use their non-LSC funds to engage in certain prohibited activities within their recipient programs during the interim period before a trial on the merits and a final ruling by the judge. This creates at least a temporary situation clearly at odds with congressional intent.

The Corporation has reviewed its policies and regulations and is making certain limited adjustments, which are intended both to preserve the statutory system created by Congress that forbids recipients from engaging in prohibited activities and subsidizing prohibited activities with LSC funds and to respond to the constitutional concerns addressed by the Court. In making these limited revisions, the Corporation is acting to reinforce its commitment to the statutory structure of prohibitions and restrictions intended by Congress without risking the possible infringement of constitutional rights where the prohibited activities are supported entirely by non-LSC funds and carried out without subsidization by the LSC grantee. Under the Court's decision, an LSC-funded entity can engage in restricted activities. While recognizing that this initial decision is not dispositive of the issue, the Corporation is mindful that Congress clearly intended to assure that no LSC-funded entity engage in restricted activities.

The Operations and Regulations Committee (''Committee'') of the Corporation's Board of Directors (''Board'') held public hearings on this matter and considered a draft interim rule on March 7, 1997. The Committee recommended and the Board agreed on March 8, 1997, to publish this revised rule as an interim rule. An interim rule is necessary in order to provide prompt and critically necessary guidance to LSC recipients on the revised legal status of these regulations, address the alleged constitutional infirmities, and yet preserve the integrity of LSC-funded programs consistent with congressional intent. Accordingly, prior notice and public comment are impracticable, unnecessary, and contrary to the public interest. See 5 U.S.C. Sections 553(b)(3)(B) and 553(d)(3). This rule is effective upon publication. However, the Corporation also solicits comment on this interim rule for review and consideration by the Committee and Board. After receipt of written public comment, the Committee intends to hold public hearings to discuss the written comments and to hear oral comments. It is anticipated that a final rule will be issued, which will supersede this interim rule.

Generally, this rule deletes provisions in Section 1610.7 on the transfer of non-LSC funds and adds a new section dealing with the integrity of recipient programs. This section also formally replaces and nullifies Section 1–7 of the Corporation's 1986 Audit and Accounting Guide, which sets out the Corporation's policy on interrelated organizations.

A section-by-section analysis is provided below.

Section 1610.1 Purpose

The purpose section is revised to reflect congressional intent that no LSC-funded organization engage in any restricted activities.

Section 1610.7 Transfers of funds

The provisions on the transfer of non-LSC funds are deleted from this section. The new § 1610.8, which sets out standards to ensure the integrity of the recipient program, has been added.

Section 1610.8 Program Integrity of Recipient

The purpose of this new section is to ensure the integrity of recipient programs. It provides that this part's restrictions on non-LSC funds will be applied to an organization found to be interrelated with a recipient such that it controls, is controlled by or is subject to common control with another organization, unless the recipient can demonstrate that it meets this part's standards of program integrity. This new policy on program integrity is based in part on the Corporation's policy on interrelated organizations, which is modified in this rule to allow recipients to have an affiliation or relationship with separate organizations which may engage in prohibited activities funded solely with non-LSC funds, provided that the standards for program integrity in this rule are met. The standards of program integrity require that there be a wall of separation between the recipient and another organization so that LSC funds will not be used to subsidize prohibited activities. Thus, although the recipient's governing body could control the other organization, the separate and distinct integrity of the recipient program is required to be maintained.

Paragraph (a) of this section essentially reflects the Corporation's old policy on interrelated organizations. It states that if a recipient controls, is controlled by or is subject to common control with another organization, the two organizations will be found to be interrelated and will be subject to the restrictions of this part unless they meet the standards of program integrity in paragraph (b). ''Control'' is defined as the ability to determine or influence the management or policies of another organization. The test for determining whether such control exists is largely the same as in the old interrelated policy, with a few adjustments that are reflected in the Section 1610.8(a)(3). The old policy stated that a determination of interrelatedness will be based on the totality of the facts and that no one factor would be determinative. This new rule retains this provision except that it cites one factor that is determinative of interrelatedness. If there is an overlap of officers and directors such that the governing body of one organization includes enough representatives of the other to cause or prevent action by the other, interrelated status will be found. Nevertheless, this interrelation does not automatically mean that the restrictions of this part will be applied to both organizations. The restrictions would only be applied if the standards of program integrity in paragraph (b) are not met.

Paragraph (b) sets out the standards of program integrity. First, the other organization must not receive any LSC funds. Second, the relationship of the recipient with the other organization must be approved by the recipient's governing body. This ensures that it is the local board, which is governed by the Corporation's governing body regulation, 45 CFR Part 1607, rather than a recipient's staff or management, that approves the relationship. The third standard requires clear physical and financial separation of the recipient from the other organization such that the recipient must have an objective integrity and independence. Factors considered to determine whether such objective integrity and independence exist include the existence of separate personnel, the existence of separate accounting and timekeeping records, the existence of separate facilities, and the extent to which signs or other forms of identification distinguish the recipient from the organization. Determinations taking into account these standards are necessary to ensure that there is no identification of the recipient with restricted activities and that the other organization is not a sham or paper organization and is not so closely identified with the recipient that there might be confusion or misunderstanding about the recipient's involvement with or endorsement of prohibited activities.

List of Subjects in 45 CFR Part 1610

Grant programs, Legal services.

For reasons set forth in the preamble, LSC revises 45 CFR Part 1610 to read as follows:

PART 1610—USE OF NON-LSC FUNDS

Sec.

1610.1 Purpose.
1610.2 Definitions.
1610.3 Prohibition.
1610.4 Authorized use of other funds.
1610.5 Notification.
1610.6 Applicability.
1610.7 Transfers of recipient funds.
1610.8 Program integrity of recipient.
1610.9 Accounting.

Authority: 42 U.S.C. 2996i; Pub. L. 104–208, 110 Stat. 3009 Pub. L. 104–134 110 Stat. 1321 (1996).

§ 1610.1 Purpose.

This part is designed to implement statutory restrictions on the use of non-LSC funds by LSC recipients and to ensure that no LSC-funded entity shall engage in any activities restricted by this part.

§ 1610.2 Definitions.

(a) *Purpose prohibited by the LSC Act* means any activity prohibited by the following sections of the LSC Act and those provisions of the Corporation's regulations that implement such sections of the Act:

(1) Sections 1006(d)(3), 1006(d)(4), 1007(a)(6), and 1007(b)(4) of the LSC Act and 45 CFR part 1608 of the LSC Regulations (Political activities);

(2) Section 1007(a)(10) of the LSC Act (Activities inconsistent with professional responsibilities);

(3) Section 1007(b)(1) of the LSC Act and 45 CFR part 1609 of the LSC regulations (Fee-generating cases);

(4) Section 1007(b)(2) of the LSC Act and 45 CFR part 1613 of the LSC Regulations (Criminal proceedings);

(5) Section 1007(b)(3) of the LSC Act and 45 CFR part 1615 of the LSC Regulations (Actions challenging criminal convictions);

(6) Section 1007(b)(7) of the LSC Act and 45 CFR part 1612 of the LSC Regulations (Organizing activities);

(7) Section 1007(b)(8) of the LSC Act (Abortions);

(8) Section 1007(b)(9) of the LSC Act (School desegregation); and

(9) Section 1007(b)(10) of the LSC Act (Violations of Military Selective Service Act or military desertion).

(b) *Activity prohibited by or inconsistent with Section 504* means any activity prohibited by, or inconsistent with the requirements of, the following sections of 110 Stat. 1321 (1996) and those provisions of the Corporation's regulations that implement those sections:

(1) Section 504(a)(1) and 45 CFR part 1632 of the LSC Regulations (Redistricting);

(2) Sections 504(a)(2) through (6), as modified by Sections 504(b) and (e), and 45 CFR part 1612 of the LSC Regulations (Legislative and administrative advocacy);

(3) Section 504(a)(7) and 45 CFR part 1617 of the LSC Regulations (Class actions);

(4) Section 504(a)(8) and 45 CFR part 1636 of the LSC Regulations (Statement of facts and client identification);

(5) Section 504(a)(9) and 45 CFR part 1620 of the LSC Regulations (Priorities);

(6) Section 504(a)(10) and 45 CFR part 1635 of the LSC Regulations (Timekeeping);

(7) Section 504(a)(11) and 45 CFR part 1626 of the LSC Regulations (Aliens);

(8) Section 504(a)(12) and 45 CFR part 1612 of the LSC Regulations (Public policy training);

(9) Section 504(a)(13) and 45 CFR part 1642 of the LSC Regulations (Attorneys' fees);

(10) Section 504(a)(14) (Abortion litigation);

(11) Section 504(a)(15) and 45 CFR part 1637 of the LSC Regulations (Prisoner litigation);

(12) Section 504(a) (16), as modified by Section 504(e), and 45 CFR part 1639 of the LSC Regulations (Welfare reform);

(13) Section 504(a)(17) and 45 CFR part 1633 of the LSC Regulations (Drug-related evictions); and

(14) Section 504(a)(18) and 45 CFR part 1638 of the LSC Regulations (In-person solicitation).

(c) *IOLTA funds* means funds derived from programs established by State court rules or legislation that collect and distribute interest on lawyers' trust accounts.

(d) *Non-LSC funds* means funds derived from a source other than the Corporation.

(e) *Private funds* means funds derived from an individual or entity other than a governmental source or LSC.

(f) *Public funds* means non-LSC funds derived from a Federal, State, or local government or instrumentality of a government. For purposes of this part, IOLTA funds shall be treated in the same manner as public funds.

(g) *Transfer* means a transfer of a recipient's funds for the purpose of conducting programmatic activities that are normally conducted by the recipient, such as the representation of eligible clients, or that provide direct support to the recipient's legal assistance activities.

(h) *Tribal funds* means funds received from an Indian tribe or from a private nonprofit foundation or organization for the benefit of Indians or Indian tribes.

§ 1610.3 Prohibition.

A recipient may not use non-LSC funds for any purpose prohibited by the LSC Act or for any activity prohibited by or inconsistent with Section 504, unless such use is authorized by §§ 1610.4, 1610.6 or 1610.7 of this part.

§ 1610.4 Authorized use of other funds.

(a) A recipient may receive tribal funds and expend them in accordance with the specific purposes for which the tribal funds were provided.

(b) A recipient may receive public or IOLTA funds and use them in accordance with the specific purposes for which they were provided, if the funds are not used for any activity prohibited by or inconsistent with Section 504.

(c) A recipient may receive private funds and use them in accordance with the purposes for which they were provided, provided that the funds are not used for any activity prohibited by the LSC Act or prohibited or inconsistent with Section 504.

(d) A recipient may use non-LSC funds to provide legal assistance to an individual who is not financially eligible for services under part 1611 of this chapter, provided that the funds are used for the specific purposes for which those funds were provided and are not used for any activity prohibited by the LSC Act or prohibited by or inconsistent with Section 504.

§ 1610.5 Notification.

(a) Except as provided in paragraph (b) of this section, no recipient may accept funds from any source other than the Corporation, unless the recipient provides to the source of the funds written notification of the prohibitions and conditions which apply to the funds.

(b) A recipient is not required to provide such notification for receipt of contributions of less than $250.

§ 1610.6 Applicability.

Notwithstanding § 1610.7(a), the prohibitions referred to in §§ 1610.2(a)(4) (Criminal proceedings), (a)(5) (Actions challenging criminal convictions), (b)(7) (Aliens) or (b)(11) (Prisoner litigation) of this part will not apply to:

(a) A recipient's or subrecipient's separately funded public defender program or project; or

(b) Criminal or related cases accepted by a recipient or subrecipient pursuant to a court appointment.

§ 1610.7 Transfers of recipient funds.

(a) For a transfer of LSC funds, the prohibitions and requirements referred to in this part, except as modified by paragraphs (b) and (c) of this section, will apply both to the funds transferred and to the non-LSC funds of the person or entity.

(b)(1) In regard to the requirement in § 1610.2(b)(5) on priorities, persons or entities receiving a transfer of LSC funds shall either:

(i) use the funds transferred consistent with the recipient's priorities; or

(ii) establish their own priorities for the use of the funds transferred consistent with 45 CFR part 1620;

(2) In regard to the requirement in § 1610.2(b)(6) on timekeeping, persons or entities receiving a transfer of LSC funds are required to maintain records of time spent on each case or matter undertaken with the funds transferred.

(c) For a transfer of LSC funds to bar associations, pro bono programs, private attorneys or law firms, or other entities for the sole purpose of funding private attorney involvement activities (PAI) pursuant to 45 CFR part 1614, the prohibitions or requirements of this part shall apply only to the funds transferred.

§ 1610.8 Program integrity of recipient.

(a) If a recipient controls, is controlled by or is subject to common control with another organization, the two organizations are interrelated organizations and the restrictions in this part will be applied to both organizations, unless the association between the two organizations meets the standards of program integrity in paragraph (b) of this section.

(1) *Control* means the direct or indirect ability to determine the direction of management and policies or influence the management or policies of another organization.

(2) Factors considered to determine whether control exists are:

(i) The extent and pattern of any overlap of officers, directors, or other managers between two organizations;

(ii) The contractual and financial relationships (especially in terms of the proportion of the organization's funds or resources that are provided by the possibly controlling organization);

(iii) The history of relationships among the organizations (e.g., the fact that one organization provided initial funding and named initial director of another would be a relevant fact; as would facts relating to decision-making on policies or transactions of mutual interest; actual control of particular decisions);

(iv) A close identity of interest;

(v) One organization has become a mere conduit, ''incorporation pocketbook,'' or ''straw'' party for another;

(vi) Funds are solicited by a separate entity in the name of and with the expressed or implicit approval of the recipient and substantially all of the funds solicited are intended by the contributor or are otherwise required to be transferred to the recipient or used at its discretion or direction;

(vii) A recipient transfers resources to another entity that holds these resources for the benefit of the recipient; and

(viii) A recipient assigns functions to an entity whose funding is primarily derived from sources other than public contributions.

(3) A determination of interrelatedness will be based on the totality of the facts and the presence or absence of any one or more factors is not determinative, except that an overlap of officers and directors such that the governing body of one organization includes enough representatives of the other to cause or prevent action by the other will be determinative that the organizations are interrelated.

(b) The restrictions in this part will not be applied to an organization found to be interrelated pursuant to paragraph (a) if:

(1) The organization receives no LSC funds, and LSC funds do not directly or indirectly subsidize restricted activities;

(2) The relationship with the organization is approved by the recipient's governing body; and

(3) The recipient is physically and financially separate from the organization. Mere bookkeeping separation of LSC funds from other funds is not sufficient. In order to be physically and financially separate, the recipient and the organization must have an objective integrity and independence from one another. Factors considered to determine whether such objective integrity and independence exist shall include, but are not limited to:

(i) The existence of separate personnel;

(ii) The existence of separate accounting and timekeeping records;

(iii) The existence of separate facilities; and

(iv) The extent to which signs and other forms of identification which distinguish the recipient from the organization are present.

§ 1610.9 Accounting.

Funds received by a recipient from a source other than the Corporation shall be accounted for as separate and distinct receipts and disbursements in a manner directed by the Corporation.

Dated: March 11, 1997.

Victor M. Fortuno,

General Counsel.

[FR Doc. 97–6542 Filed 3–13–97; 8:45 am]

BILLING CODE 7050–01–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 73

[MM Docket No. 95–142; RM–8685]

Radio Broadcasting Services; Zapata, TX

AGENCY: Federal Communications Commission.

ACTION: Final rule.

SUMMARY: The Commission, at the request of Arturo Lopez, allots Channel 228A at Zapata, Texas, as the community's first local FM service. *See* 60 FR 46562, September 7, 1995. Channel 228A can be allotted to Zapata in compliance with the Commission's minimum distance separation requirements without the imposition of a site restriction. The coordinates for Channel 228A at Zapata are 26–54–30 NL and 99–16–18 WL. Since Zapata is located within 320 kilometers (199 miles) of the U.S.-Mexican border, concurrence of the Mexican government has been obtained for this allotment.With this action, this proceeding is terminated.

DATES: Effective April 21, 1997. The window period for filing applications will open on April 21, 1997, and close on May 22, 1997.

FOR FURTHER INFORMATION CONTACT: Pam Blumenthal, Mass Media Bureau, (202) 418–2180.

SUPPLEMENTARY INFORMATION: This is a synopsis of the Commission's Report and Order, MM Docket No. 95–142, adopted February 26, 1997, and released March 7, 1997. The full text of this Commission decision is available for inspection and copying during normal business hours in the FCC Reference Center (Room 239), 1919 M Street, NW, Washington, DC. The complete text of this decision may also be purchased from the Commission's copy contractor, ITS, Inc., (202) 857–3800, 2100 M Street, NW, Suite 140, Washington, DC 20037.

List of Subjects in 47 CFR Part 73

Radio broadcasting.

Part 73 of title 47 of the Code of Federal Regulations is amended as follows:

PART 73—[AMENDED]

1. The authority citation for Part 73 continues to read as follows:

Authority: Secs. 303, 48 Stat., as amended, 1082; 47 U.S.C. 154, as amended.

§ 73.202 [Amended]

2. Section 73.202(b), the Table of FM Allotments under Texas, is amended by adding Zapata, Channel 228A.

Federal Communications Commission.

John A. Karousos,

Chief, Allocations Branch, Policy and Rules Division, Mass Media Bureau.

[FR Doc. 97–6429 Filed 3–13–97; 8:45 am]

BILLING CODE 6712–01–F

47 CFR Part 73

[MM Docket No. 96–122; RM–8795; RM–8860]

Radio Broadcasting Services; Riverdale and Huron, CA

AGENCY: Federal Communications Commission.

ACTION: Final rule.

SUMMARY: This document dismisses a petition for rule making filed by Happy Nice Valley Broadcasting requesting the allotment of Channel 252A to Riverdale, California, as that locality's first local aural transmission service (RM–8795). The proposal is dismissed based upon the lack of interest by the petitioner or any other interested party to provide information, as requested, to establish that Riverdale constitutes a *bona fide* ''community'', as that term is defined for purposes of Section 307(b) of the Communications Act, as amended by the Telecommunications Act of 1996, for allotment objectives. *See* 61 FR 30585, June 17, 1996. However, in response to a counterproposal filed by Radio Coalinga Latino, Channel 252A is allotted to the incorporated community of Huron, California, as that locality's first local aural transmission service (RM–8860). Coordinates used for Channel 252A at Huron, California, are 36–15–41 and 120–04–19. With this action, the proceeding is terminated.

DATES: Effective April 21, 1997. The window period for filing applications on Channel 252A at Huron, California, will open on April 21, 1997, and close on May 22, 1997.

FOR FURTHER INFORMATION CONTACT: Nancy Joyner, Mass Media Bureau, (202) 418–2180. Questions related to the window application filing process for Channel 252A at Huron, California, should be addressed to the Audio Services Division, (202) 418–2700.

SUPPLEMENTARY INFORMATION: This is a synopsis of the Commission's Report and Order, MM Docket No. 96–122, adopted February 26, 1997, and released March 7, 1997. The full text of this Commission decision is available for inspection and copying during normal business hours in the FCC's Reference Center (Room 239), 1919 M Street, NW., Washington, DC. The complete text of this decision may also be purchased from the Commission's copy contractors, International Transcription Services, Inc., 2100 M Street, NW., Suite 140, Washington, DC 20037, (202) 857–3800.

List of Subjects in 47 CFR Part 73

Radio broadcasting.

Part 73 of Title 47 of the Code of Federal Regulations is amended as follows:

PART 73—[AMENDED]

1. The authority citation for Part 73 continues to read as follows:

Authority: Secs. 303, 48 Stat., as amended, 1082; 47 U.S.C. 154, as amended.

§ 73.202 [Amended]

2. Section 73.202(b), the Table of FM Allotments under California, is amended by adding Huron, Channel 252A.

Federal Communications Commission.

John A. Karousos,

Chief, Allocations Branch, Policy and Rules Division, Mass Media Bureau.

[FR Doc. 97–6428 Filed 3–13–97; 8:45 am]

BILLING CODE 6712–01–F

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 648

[Docket No. 961129337–7040–02; I.D. 112096A]

RIN 0648–XX75

Fisheries of the Northeastern United States; Summer Flounder, Scup, and Black Sea Bass Fisheries; 1997 Scup Specifications

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Final rule and final specifications for the 1997 scup fishery.

SUMMARY: NMFS issues the final specifications for the 1997 scup fishery that include a commercial catch quota, a recreational harvest limit, and other management measures. The intent of these measures is to prevent overfishing of the scup resource.

DATES: The amendment to § 648.123(a)(1) is effective April 14, 1997. The final 1997 scup specifications are effective March 11, 1997 through December 31, 1997.

ADDRESSES: Copies of the Mid-Atlantic Fishery Management Council's analysis and recommendations are available from David R. Keifer, Executive Director, Mid-Atlantic Fishery Management Council, Room 2115, Federal Building, 300 South New Street, Dover, DE 19904–6790.

FOR FURTHER INFORMATION CONTACT: Lucille L. Helvenston, Fishery Management Specialist (508) 281–9347.

SUPPLEMENTARY INFORMATION: Comprehensive measures enacted by Amendment 8 to the Summer Flounder, Scup, and Black Sea Bass Fishery Management Plan (FMP) were designed to rebuild the severely depleted scup stock. Amendment 8 established a Monitoring Committee that meets annually to review the best available scientific data and make recommendations regarding the catch quota and other management measures in the FMP. The Committee's recommendations are made to achieve the target exploitation rates established in the amendment to reduce overfishing. The Committee bases its recommendations on: (1) Commercial and recreational catch data; (2) current estimates of fishing mortality; (3) stock status; (4) recent estimates of recruitment; (5) virtual population analysis (VPA); (6) levels of regulatory noncompliance by fishermen or individual states; (7) impact of fish size and net mesh regulations; (8) impact of gear other than otter trawls on the mortality of scup; and (9) other relevant information.

Based on the recommendations of the Monitoring Committee, the Mid-Atlantic Council's Demersal Species Committee makes a recommendation to the Council, which in turn makes a recommendation to the Administrator, Northeast Region, NMFS. The Council recommended a commercial quota, recreational harvest limit, and changes in the minimum mesh regulations for 1997.

The measures contained in this final action are unchanged from those in the proposed rule published December 9, 1996, (61 FR 64854) and are: (1) A coastwide commercial quota of 6.0 million lb (2.7 million kg); (2) a recreational harvest limit of 1.947 million lb (0.88 million kg); (3) an increase in the minimum codend mesh size from 4.0 inches (10.21 cm) to 4.5 inches (11.43 cm) and (4) seasonal minimum mesh threshold levels of 4,000 lb (1,814 kg) in the winter months (November—April) and 1,000 lb (453 kg) in the sumer months (May—October). Detailed background information concerning these measures is provided in the proposed rule and is not repeated here.

The coastwide quota is for the 1997 fishing year, January 1, 1997, through December 31. 1997. However, the Council has proposed a regulatory change in a separation action that would divide the quota into three seasons: Winter 1 (January—April), Summer (May—October) and Winter 2 (November—December). The winter quota would be coastwide. The summer quota would be allocated on a state-by-state basis. Trip limits would be imposed in the winter periods. If this proposal is approved, it would be implemented about mid-1997.

Comments and Responses

The Mid-Atlantic Fishery Management Council (Council) submitted a comment in support of the 1997 specifications for the scup fishery. The Department of Marine Fisheries of the Commonwealth of Massachusetts (MADMF) and an individual submitted comments in opposition to the proposed 1997 specifications for the scup fishery.

Comment: Both MADMF and the individual commenter believe the NMFS should not implement the 1997 coastwide commercial quota for several reasons. The individual commenter asserts that the absence of any constraints on the harvest of the coastwide quota allows the winter offshore fishery to catch all of the quota and discriminates against inshore harvesters. The MADMF states that, without the proposed regulatory change to the quota system, the quota will be harvested early in the year and there will be negative impacts from the resulting fishery closure. MADMF also notes that quota monitoring should be improved prior to implementation.

Response: The FMP requires NMFS to implement a coastwide commercial quota for 1997. NMFS has no legal authority to defer implementation of the quota until the regulatory amendment is approved. While NMFS is actively involved in the ongoing efforts to improve quota monitoring, particularly for state fisheries, NMFS disagrees with the implication that the existing monitoring system is inadequate for scup quota management. Further, NMFS disagrees with the contention that the quota is discriminatory. The quota in and of itself is not discriminatory. Although these measures may have negative impacts on different sectors of the fishery because of the distance from areas in which scup are available, the regulatory measures are not in and of themselves discriminatory. The review of the amendment concluded that it was consistent with the national standards of the Magnuson-Stevens Fishery Conservation and Management Act and with other applicable law. NMFS notes that the amendment applies to the coastwide fishery rather than just to the Massachusetts industry, which the amendment shows has historically accounted for only 7 percent of the coastwide scup landings.

Comment: MADMF comments that the implementation of the quota and the anticipated fishery closure will not prevent regulatory discards in the small mesh fisheries, particularly the squid fishery. MADMF proposes that, if the quota is implemented for 1997, NMFS should revise the manner in which discards are accounted for in calculating the quota. MADMF proposes that discards should only be considered if they occur in fisheries that are directed towards scup.

Response: The minimum mesh requirement and the associated catch threshold are intended to discourage vessel operators using small mesh for other species from continuing to fish when they encounter large amounts of scup that they would be required to sort out from other species and discard. The FMP also specifies that the annual total allowable catch (TAC) will be set to attain the target exploitation rates specified in the plan. Because the TAC represents the sum of discards and quota, there is an incentive for the industry to reduce discards in order to increase quotas. NMFS cannot modify the FMP as suggested by MADMF to change the manner in which discards are deducted from the TAC.

MNFS notes that if these measures do not have the desired effects on discard levels, the FMP provides the Council with the option of specifying season and area closures in the future if necessary to address such concerns.

Comment: The individual commenter stated that fishermen from Massachusetts were not represented in the scup management process and were unfairly impacted.

Response: The process to adopt and implement the amendment involved public hearings where members of the industry among other members of the public were allowed to comment on the proposed measures. NMFS notes that in 1995, hearings were held in New Bedford, MA, and Newport, RI, on July 18th and July 17th, respectively. The proposed rule also solicited comments from the public that were considered by NMFS in the review of the amendment. Therefore, NMFS concludes that Massachusetts industry participants were given several opportunities to be represented in the scup management process.

Comment: MADMF suggested that the 4,000-lb (1,814-kg) threshold that will trigger the minimum mesh requirement should be decreased to 100 lb (45 kg). MADMF proposes that this decrease will lessen the discards of small juvenile scup.

Response: The 4,000-lb (1,814-kg) threshold that will trigger the minimum mesh requirement was set in response to analysis of scientific data and public comment. The amendment showed that in 1992 and 1993, a large share of the total scup landings (80 percent) was comprised of landings in excess of 4,000 lb (1,814 kg). Therefore, the threshold was set at 4,000 lb (1,814 kg) to target the majority of vessels landing scup. A much lower threshold would penalize a large number of vessels that catch small amounts of scup as a catch in various mixed trawl fisheries. These vessels will be forced to discard legal size scup if they are caught while fishing for other species with mesh smaller than the scup minimum size. The cost that would be borne by the industry as the result of a drastic reduction in the threshold greatly outweighs the benefits that would accrue to the stock. The 4,000-lb (1,814-kg) threshold allows vessel operators to retain and land legal size scup that will be counted toward the quota.

Comment: MADMF and the individual commenter both disagree with NMFS' conclusion in the preamble of the proposed rule that the proposed measures will not have a significant economic impact on a substantial number of small entities. MADMF notes that NMFS concluded that the effect of the quota will be minimal because the 1997 quota level is not significantly lower than the commercial landings in 1995, the most recent year for which data are available. MADMF states that the scup landings data for the Massachusetts fishery are incomplete. Therefore, the effect of the quota will not be minimal for the State's industry. MADMF also asks why the commercial quota is not reduced from the 1995 level if the scup stock is severely depleted.

Response: NMFS disagrees with MADMF and the individual commenter that the incomplete data from the State of Massachusetts would alter the conclusion that there are no significant impacts on the industry. While NMFS accepts that MADMF may well be correct in stating that these data are incomplete for Massachusetts, NMFS cannot conclude that there is a significant impact on industry based solely on such a statement. NMFS based its conclusions concerning the economic impacts of these measures on the best available data. NMFS notes that the regulatory amendment for the scup fishery, currently under review, invites state fisheries agencies to update the landings data for their states in order to make future adjustments to the summer state quota shares. NMFS encourages MADMF to take such action if the regulatory amendment is approved.

NMFS believes that these annual specifications address the depleted nature of the scup stock. The 1997 reductions in exploitation are anticipated to be realized due to a reduction in discards rather than a reduction in landings. The Council selected a TAC level of 9.11 million lb (4.13 million kg) as having a 50 percent probability of achieving the target exploitation rate of 47 percent for 1997. The TAC was then divided between the commercial and recreational sectors of the fishery in the shares specified in the FMP (78 percent commercial and 22 percent recreational). The specifications of 6.0 million lb (2.7 million kg) for the commercial quota and 1.947 million lb (0.88 million kg) for the recreational harvest limit were derived from the respective TACs by subtracting the expected discards for 1997 (97 percent of the discards are allocated to the commercial fishery and 3 percent are allocated to the recreational fishery). The amount subtracted from the commercial TAC was reduced to account for an anticipated decrease in discards due to the implementation of minimum mesh size and fish size restrictions in 1996 and 1997.

Comment: MADMF expresses concern that the quota will alter fishermen's behavior and anticipates a change in the fishery for summer flounder (fluke).

Response: It is unclear from the comment what change MADMF anticipates or what action it is advocating. NMFS cannot respond other than to agree that the imposition of management measures on a fishery that was not previously regulated is intended to alter fishing behavior to the benefit of the stock and to the long-term benefit of the industry.

Comment: A comment from the Council supports the 1997 specifications for the scup fishery.

Response: NMFS notes the Council's support of the 1997 specifications for the scup fishery.

Classification

This action is authorized by 50 CFR part 648 and has been determined not to be significant for purposes of E.O. 12866.

The Assistant General Counsel for Legislation and Regulation, Department of Commerce, certified to the Chief Counsel for Advocacy of the Small Business Administration that this rule would not have a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (RFA). The reasons for the finding of no significant economic impact under the RFA were discussed in the proposed rule published in the Federal Register on December 9, 1996 (61 FR 64854), and are not repeated here. NMFS received several comments, which are addressed above, regarding this certification. These comments did not cause NMFS to change its determination regarding the certification. As a result, no regulatory flexibility analysis was prepared.

List of Subjects in 50 CFR Part 648

Fisheries, Fishing, Reporting and recordkeeping requirements.

Dated: March 10, 1997.

Rolland A. Schmitten,

Assistant Administrator for Fisheries, National Marine Fisheries Service.

For the reasons set out in the preamble, 50 CFR Part 648 is amended to read 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 § 648.123, paragraph (a)(1) is revised to read as follows:

§ 648.123 Gear restrictions.

(a) *Travel vessel gear restrictions*—(1) *Minimum mesh size.* The owners or operators of otter trawlers issued a scup moratorium permit, and that possess 4,000 lb or more (1,814 kg or more) of scup from November 1 through April 30 or 1,000 lb or more (454 kg or more) of scup from May 1 through October 31 must fish with nets that have a minimum mesh size of 4.5 inches (11.43 cm) diamond mesh, applied throughout the codend for at least 75 continuous meshes forward of the terminus of the net, or for codends with less than 75 meshes, the minimum-mesh-size codend must be a minimum of one-third of the net, measured from the terminus of the codend to the head rope, excluding any turtle excluder device extension. Scup on board these vessels shall be stored separately and kept readily available for inspection.

* * * * *

[FR Doc. 97–6483 Filed 3–11–97; 4:32 pm]

BILLING CODE 3510–22–M

Proposed Rules

Federal Register

Vol. 62, No. 50

Friday, March 14, 1997

DEPARTMENT OF AGRICULTURE

Food and Consumer Service

7 CFR Parts 250, 251, and 253

RIN 0584–AB27

Food Distribution Programs—Reduction of the Paperwork Burden

AGENCY: Food and Consumer Service, USDA.

ACTION: Proposed rule.

SUMMARY: This rule proposes to amend the Food Distribution Program regulations, the Emergency Food Assistance Program regulations, and the Food Distribution Program for Households on Indian Reservations regulations to implement the provisions of the Child Nutrition and WIC Reauthorization Act of 1989 regarding paperwork reduction for food distribution programs. The proposals contained in this rule would extend the maximum effective periods for agreements between Federal, distributing, and recipient agencies, contracts of distributing and subdistributing agencies with storage facilities, contracts between recipient agencies and food service management companies, and State plans of operation; remove the requirement that commodity acceptability information be submitted for the following program categories: charitable institutions, nonprofit summer camps, the Summer Food Service Program for Children, and the Emergency Food Assistance Program; relax monitoring requirements for distributing agencies with regard to charitable institutions and nonprofit summer camps, and the food service management companies under contract with them; and, amend regulatory language to reflect modified information collection requirements. The proposals would, in short, effect a substantial reduction in the information collection requirements imposed on distributing and recipient agencies, and the paperwork generated in fulfilling these requirements, in administering food distribution programs.

DATES: To be assured of consideration, comments must be postmarked on or before May 13, 1997.

ADDRESSES: Comments should be sent to: Lillie Ragan, Assistant Branch Chief, Household Programs Branch, Food Distribution Division, Food and Consumer Service, U.S. Department of Agriculture, Park Office Center, Room 502, 3101 Park Center Drive, Alexandria VA 22302–1594. Comments in response to this rule may be inspected at 3101 Park Center Drive, Room 502, Alexandria VA, during normal business hours (8:30 a.m. to 5 p.m., Mondays through Fridays).

FOR FURTHER INFORMATION CONTACT: Lillie Ragan at the above address or telephone (703) 305–2662.

SUPPLEMENTARY INFORMATION:

Executive Order 12866

This proposed rule has been determined to be not significant for purposes of Executive Order 12866, and therefore has not been reviewed by the Office of Management and Budget for any purpose other than approval of the changes in the information collection burden proposed in the rule.

Regulatory Flexibility Act

This action has also been reviewed with regard to the requirements of the Regulatory Flexibility Act of 1980 (5 U.S.C. 601–612). The Administrator of the Food and Consumer Service (FCS) has certified that this action will not have a significant economic impact on a substantial number of small entities. The procedures in this rulemaking would primarily affect FCS Regional Offices, and the distributing and recipient agencies that administer food distribution programs. Private enterprises that enter into agreements for the storage of donated food or meal service management would also be affected. While some of these entities constitute small entities, a substantial number will not be affected. Further, any economic impact will not be significant.

Executive Order 12372

These programs are listed in the Catalog of Federal Domestic Assistance under 10.550, 10.568, and 10.569, respectively, and are subject to the provisions of Executive Order 12372, which requires intergovernmental consultation with State and local officials (7 CFR part 3015, Subpart V and final rule-related notices published at 48 FR 29114, June 24, 1983 and 49 FR 22676, May 31, 1984).

Paperwork Reduction Act

In accordance with the Paperwork Reduction Act of 1995 (44 U.S.C. 3507), the Food and Consumer Service is submitting for public comment the changes in the information collection burden that would result from the adoption of the proposals in the rule.

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 will have practical utility; (b) 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; (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 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. To be assured of consideration, comments must be postmarked on or before May 13, 1997. Comments may be sent to Wendy Taylor, Desk Officer, Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), Washington DC 20503. All comments will be summarized and included in the request for OMB approval of the proposed changes in the information collection burden. All comments will become a matter of public record. For further information, or for copies of the information collections discussed below, please contact Lillie Ragan, Assistant Branch Chief, Household Programs Branch, Food Distribution Division, Food and Consumer Service, U.S. Department of Agriculture, Park Office Center, Room 502, 3101 Park Center Drive, Alexandria, Virginia 22302–1594, or telephone (703)305–2662.

Title: Food Distribution Regulations and Forms.

OMB Number: 0584–0293.

Expiration Date: 9/30/97.

Type of Request: Revision of a currently approved collection.

Abstract: Agreements, contracts, and plans of operation. The rule proposes to: (1) make agreements between distributing agencies and recipient agencies (food banks, soup kitchens, charitable institutions, emergency feeding organizations, etc.) to operate food distribution programs permanent, with amendments made as necessary, instead of annual; (2) allow distributing or subdistributing agencies to sign contracts with storage facilities for the storage of donated foods for a maximum duration of five years, instead of the present one year, with options for two additional years; (3) allow recipient agencies (charitable institutions, summer camps, and nutrition programs for the elderly) to sign contracts with food service management companies for one year, with four additional one-year options, instead of one year with two additional one-year options; and, (4) make the plan submitted by State agencies and Indian Tribal Organizations to operate the Food Distribution Program on Indian Reservations (FDPIR) ongoing, instead of annual, with amendments made as necessary.

Submission of Inventory Reports. The rule proposes to require semiannual submission of the recently revised form FCS–155, the Inventory Management Register (the revised form has been approved by OMB). This form is a report of excessive commodity inventories—i.e., inventories exceeding a six-month supply—that helps to ensure that commodities will be utilized before going out of condition. Regulations presently require monthly submission of form FCS–155.

Collection of Commodity Acceptability Information. The rule proposes to exclude certain food distribution program categories from those for which distributing agencies must submit commodity acceptability information, because of the substantial reduction in surplus commodities now available to these programs. The exempted program categories would be charitable institutions, summer camps, the Summer Food Service Program for Children (SFSP), and the Emergency Food Assistance Program (TEFAP). Commodity acceptability information is collected for other food distribution programs to ensure that commodities distributed are of the types and forms most acceptable to program recipients.

Respondents: Respondents include State agencies and Indian Tribal Organizations administering food distribution programs, and, in some cases, recipient agencies responsible for local administration and distribution of donated commodities.

Estimated Number of Respondents: State agencies and Indian Tribal Organizations administering food distribution programs number 171; recipient agencies number approximately 11,200.

Estimated Number of Responses per Respondent: Frequency of response for the inventory reports would be semiannual, or 2 per year. Frequency of response for agreements between distributing and recipient agencies, the State plans, and the distributing and recipient agency contracts with storage facilities and food service management companies would vary, depending on necessary amendments to the agreements and plans, and the length of the contracts. It is estimated that, on average, both amendments and contracts would be completed every four years, or at a frequency of 0.25 per year. Frequency of response for the commodity acceptability reports would continue to be annual, but distributing agencies would not be required to submit commodity acceptability information for charitable institutions, summer camps, SFSP, and TEFAP, thus reducing the number of responses to be submitted.

Estimate of Burden: The present and proposed estimates of the reporting burden for the information collections affected by this rule are detailed below. These estimates are based on information obtained from distributing and recipient agencies administering food distribution programs through various vehicles such as meetings and the review of information submitted in State plans. The information includes the number of respondents, frequency of responses per year for each respondent, number of hours per response, and the total burden hours for each information collection.

	Respndnts.	Freq.	Hrs./Resp.	Total Hrs.
Distributing and Recipient Agency Agreement:				
Present	11,211	1	0.33	3,700
Proposed	11,211	0.25	0.20	561
Distributing or Subdistributing Agency Contracts w/Storage Facilities:				
Present	250	1	0.33	83
Proposed	250	0.25	0.33	21
Contracts w/Food Service Management Companies:				
Present	300	1	0.33	99
Proposed	300	0.25	0.33	25
Inventory Reports (FCS–155):				
Present	80	12	1.75	1,680
Proposed	80	2	0.25	40
Commodity Acceptability Reports:				
Present	466	1	50	23,300
Proposed	252	1	50	12,600
FDPIR State Plan:				
Present	97	1	10	970
Proposed	97	0.25	3	73

Estimated Total Annual Burden on Respondents: The total annual burden under OMB Control Number 0584–0293 would be reduced from 1,190,971 hours to 1,174,459 hours: a difference of 16,512 hours.

Title: Federal-State Agreement, FCS–74

OMB Number: 0584–0067

Expiration Date: 6/30/98

Type of Request: Revision of a currently approved collection.

Abstract: The Federal-State Agreement, form FCS–74, is used to ensure that distributing agencies administering child nutrition and food distribution programs comply with Federal regulations applicable to the programs. This rule proposes to make permanent, instead of annual, the agreement that distributing agencies administering food distribution programs (and not child nutrition programs) sign with the Food and Consumer Service (FCS). Amendments would be made as necessary, at the request of FCS.

Respondents: State agencies and Indian Tribal Organizations administering food distribution programs.

Estimated Number of Respondents: 147 State agencies and Indian Tribal Organizations would be affected.

Estimated Number of Responses per Respondent: The agreements would be permanent for the affected State agencies, with amendments to the agreement submitted as necessary. It is estimated that such amendments would be required, on average, every four years. Thus, the annual number of responses per respondent would be 0.25.

Estimate of Burden: The following estimates are based on the anticipated frequency of need for changes. For each of the 147 affected State agencies and Indian Tribal Organizations, the agreement would take approximately 0.25 hours to complete, and would be completed, on average, 0.25 times per year. Thus, the annual reporting burden for these agencies would be 9.2 hours.

Estimated Total Annual Burden on Respondents: The total annual burden under OMB Number 0584–0067 would be reduced from 34,494 hours to 34,466 hours: a difference of 28 hours.

Executive Order 12988

This proposed rule has been reviewed under Executive Order 12988, Civil Justice Reform. This rule is intended to have preemptive effect with respect to any State or local laws, regulations or policies which conflict with its provisions, or which would otherwise impede its full implementation. This rule is not intended to have retroactive effect unless so specified in the ''Effective Date'' section of the preamble of the final rule. There are no administrative procedures which must be exhausted prior to any judicial challenge to the provisions of this rule or the application of its provisions.

Background

The Child Nutrition and WIC Reauthorization Act of 1989, Pub. L. 101–147, (hereinafter referred to as ''the Act''), was enacted on November 10, 1989. Section 108 of the Act amended what was then Section 19 of the National School Lunch Act (NSLA), 42 U.S.C 1769a, to include a requirement that the Secretary endeavor to reduce the paperwork burden for State and local educational agencies, schools, and other agencies participating in nutrition assistance programs. The Act required that, in determining ways to reduce the paperwork burden, the Secretary (1) consult with State and local administrators of nutrition assistance programs; (2) convene at least one meeting with the program administrators; and (3) solicit suggestions from the general public. (Section 710 of Pub. L 104–193, the Personal Responsibility and Work Opportunity Reconciliation Act of 1996, repealed Section 49 of the NSLA.)

Accordingly, on April 9, 1990, a Notice was published in the Federal Register (55 FR 13156) soliciting comments regarding the reduction of the paperwork burden associated with the administration of the child nutrition and food distribution programs. One hundred and sixty-five comments addressing issues associated with paperwork reduction for food distribution programs were received. Comments were received from 105 schools, 49 State agencies, five food processors, four professional associations (including the American Commodity Distribution Association and the American School Food Service Association), one Indian Tribal Organization, and one consultant. Following the receipt of comments, on July 30, 1990, a Paperwork Reduction Task Force (hereinafter referred to as the ''Task Force''), comprised of representatives from two commodity distribution associations, 13 school or food distribution program administrators, and two FCS Regional Office directors, was convened to review the comments received in response to the Notice. The actions taken to date by the Department in response to Congress' directive in Section 108 of Pub. L. 101–147 are discussed in detail below.

Five commenters recommended that the amount of information a State is required to submit to the Department before a commodity complaint can be investigated be reduced. In response to these recommendations, through consultation with FCS Regional Office and State agency representatives, a list of data that must be provided prior to FCS taking any action regarding a complaint was developed and made available to all Regional Offices for dissemination to State agencies. While other information may subsequently be requested, submission of all required basic data at the time the complaint is reported permits FCS to begin taking appropriate action in a much more timely manner.

FCS has also taken steps to simplify the process of transmitting the data needed to act on commodity complaints by revising the Special Nutrition Programs Integrated Information System (SNPIIS) to allow FCS Regional Offices to submit complaint data electronically. An informational booklet containing instructions as to how to input complaint data into the system has been disseminated to all FCS Regional Offices.

In order to streamline the process of reporting commodity complaints, FCS has set up a telephone ''hot line'' for use on a pilot basis. Under the pilot project, selected distributing or recipient agencies within certain States may report commodity complaints to FCS Headquarters directly, via a toll-free 800 number or facsimile machine. All FDPIR State agencies, including all Indian Tribal Organizations acting as State agencies pursuant to 7 CFR 253.2(h), may report commodity complaints to FCS Headquarters directly via the hot line also. While those agencies utilizing the hot line must still provide certain basic information before the problem can be resolved, they have more flexibility in the format used to report the information than those agencies reporting commodity complaints through State and FCS Regional offices, and receive a more immediate response to their concerns. If the pilot project, the initial phase of which concluded on September 30, 1996, indicates that direct reporting of commodity complaints to the national office provides better service to the recipients utilizing USDA commodities, by reducing the amount of time required to resolve complaints, then access to the hot line will be extended to all States.

Five commenters suggested that the Department allow distributing agencies to waive commodity losses of $100 or less. Since this was already the Department's policy, the Department has considered how to provide clarification of the policy. In addition, FCS has consulted with Regional Offices to resolve various issues relating to losses resulting from the improper storage or distribution of commodities, including the responsibility for initiating claims, and the cost efficiency of the claims process. This consultation has resulted in the development of draft guidance material which was disseminated to FCS Regional Offices for comment on April 15, 1994. The guidance material establishes the Department's position on issues relative to: (1) what entity is responsible for pursuing the various types of claims; (2) conditions under which storage facilities can offset shortages with overages; (3) allowable uses of funds derived from salvage and recycling; (4) what funds should be deposited into the distributing agency's general salvage account and the allowable uses of such funds; (5) the handling of losses of ''bonus'' commodities; and (6) the thresholds that have been established for use in determining what entity has the authority to make a claim determination, and to compromise, waive, or suspend claims. Several of the changes discussed in the guidance material have been implemented through policy memoranda. However, some changes can only be effectuated by revising ''Non-Audit Claims—Food Distribution Program,'' FCS Instruction 410–1, and/or through the rulemaking process. The issue of increasing the limit under which State agencies can waive a claim is one that must be addressed through the rulemaking process for the Emergency Food Assistance Program (TEFAP) and by revision of the FCS instruction for all other food distribution programs.

Twenty-one commenters suggested that forms FCS–155 (Monthly Report of Receipt and Distribution of Donated Foods) and FCS–155A (Shipment of Commodities by Delivery Order) be eliminated, or that these inventory reports be required less frequently. After a review of the usefulness of the forms in 1991 and 1992, FCS concluded that it would not be feasible to eliminate them, but that they could be modified to reduce the paperwork burden for State agencies. Accordingly, forms FCS–155 and FCS–155A were modified by removing some columns that collected duplicate information.

With full implementation of the Processed Commodities Inventory Management System (PCIMS), FCS decided to reexplore the usefulness of forms FCS–155 and FCS–155A, and initiated a pilot project in 1994 to determine if information entered in PCIMS would make the collection of information in the reports redundant. After identifying relevant information that can be accessed through this system, an alternate, less time-consuming inventory reporting form was developed for use by those State agencies participating in the pilot project. After evaluating the results of the pilot project, this form—the revised FCS–155—was further refined to collect information on excessive commodity inventories only, and not the detailed information on receipt and distribution of commodities currently reported. Excessive commodity inventories are defined in 7 CFR 250.14(f) as those that exceed a six-month supply. The revised FCS–155—renamed the Inventory Management Register—was submitted for approval to the Office of Management and Budget (OMB), and was approved by OMB on September 13, 1995, as part of OMB #0584–0293. Also resulting from the pilot project, submittal of form FCS–155A, which served to verify receipt of shipments of commodity delivery orders, was found to be unnecessary. Distributing agencies report receipts for foods delivered to the Kansas City Commodity Office, utilizing form KC–269A, the Distributing Agency Consignee Receipt, as directed in FCS Instruction 709–5, Shipment and Receipt of Foods. Thus, distributing agencies administering child nutrition and food distribution programs—except for FDPIR and the Commodity Supplemental Food Program (CSFP)—now submit the revised FCS–155, the Inventory Management Register, to FCS regional offices, and no longer submit form FCS–155A. State agencies and Indian Tribal Organizations administering FDPIR and CSFP submit more detailed information on program participation, inventories of donated foods, and distribution of donated foods to households, on a monthly basis, utilizing forms FCS–152 (for FDPIR) and FCS–153 (for CSFP). Unlike other programs, the information reported on these inventory forms is not currently available through automated systems. Thus, State agencies and Indian Tribal Organizations must continue to submit forms FCS–152 and FCS–153 for FDPIR and CSFP, respectively. As with other programs, however, the submittal of form FCS–155A to verify the shipment of commodities by delivery order is no longer required. This form was discontinued in October 1995 for FDPIR, and in November 1995 for CSFP.

Twenty-eight commenters to the 1990 Notice suggested that commodity acceptability reports be submitted annually, rather than semi-annually, as was then required by law. Subsequent to the publication of the Notice, however, Section 1773(d) of Pub. L. 101–624, the Food, Agriculture, Conservation, and Trade Act of 1990, subsequently amended Section 3(f)(2) of the Commodity Distribution Reform Act and WIC Amendments of 1987 (Pub. L. 100–237; 7 U.S.C. 612c note) to require the collection of commodity acceptability information annually. In order to further reduce the paperwork burden, however, we are proposing to amend regulations to exempt certain program categories from the annual reporting requirement, while still conforming to the mandate of Pub. L. 100–237. This proposal is described below, in the section of this preamble entitled ''Food Distribution Program Regulations (7 CFR Part 250).''

Additionally, a revision of form FCS–663, Commodity Acceptability Report, has been developed with input from FCS Regional Offices and State agencies. This revised form will substantially decrease the paperwork burden for distributing and recipient agencies in reporting commodity acceptability information, while still providing valuable information on the commodity preferences of program recipients. The revised form FCS–663 was approved by OMB on September 13, 1995, as part of OMB #0584–0293.

Five commenters recommended that the State plan describing the operation and administration of TEFAP, presently submitted annually, be considered permanent, with amendments submitted as specific changes in the administration of the program are made. However, on August 22, 1996, President Clinton signed into law the Personal Responsibility and Work Opportunity Reconciliation Act of 1996, Pub. L. 104–193, which, in Section 871(b) amended Section 202A of the Emergency Food Assistance Act of 1983, Pub. L. 98–8 (7 U.S.C. 7503(a)), to require State agencies to submit a TEFAP State plan every four years, with amendments submitted as necessary, for the Department's approval. The four-year requirement for submission of the TEFAP State Plan, instead of annual submission, became effective on August 22, 1996. The Department will address these, as well as other changes in the administration of TEFAP resulting from passage of Pub. L. 104–193, through a separate rulemaking.

Four commenters recommended that the distributing agency evaluation of the cost efficiency of storage facilities be discontinued, or required less frequently. The requirement that distributing agencies periodically evaluate the cost-effectiveness of their current storage systems (7 CFR 250.14) will be addressed in a separate rule.

Comments relative to commodity processing have been addressed in a final rule which was published in the Federal Register on December 7, 1994 (59 FR 62973).

In addition to the policy and regulatory changes discussed above, the Department is proposing to amend several regulatory requirements contained in Parts 250, 251, and 253, based on comments received in response to the Notice. The proposed regulatory amendments contained in this rule are discussed in detail below.

Food Distribution Program Regulations (7 CFR Part 250)

Duration Requirements for Agreements and Contracts

Currently, Section 250.12(a) of the regulations requires that distributing agencies enter into agreements with the Department that are effective for only one year. In addition, Section 250.12(b) limits agreements between State and recipient entities to only one year, with the possibility of two one-year extensions. Sections 250.12(b) and 250.14(d) limit the length of contracts of distributing and subdistributing agencies with storage facilities to only one year, with the possibility of two one-year extensions. These regulations also restrict the length of contracts between distributing agencies and carriers to the same duration limits. Agreements between State agencies and subdistributing or recipient agencies must establish (1) the conditions under which donated foods will be made available, and (2) responsibility for loss, damage, or improper use of donated foods. Agreements of State or subdistributing agencies with storage facilities must contain provisions designed to ensure that storage facilities properly identify, store, and account for donated commodities.

Numerous commenters suggested that the one-year limit on agreements be removed. Thirty-one commenters suggested that agreements between State and recipient agencies be made permanent with provision for amendments as necessary. Eleven commenters also suggested that the annual agreement between the Department and State agencies be made permanent. Eighteen commenters also recommended extending the duration of contracts between distributing and subdistributing agencies and storage facilities for the storage of donated foods.

The Department agrees that requiring Federal-State agreements to be completed anew each year is burdensome and unnecessary. Accordingly, this rule proposes to amend § 250.12(a) to provide for permanent agreements between the Department and State agencies, with amendments to be made at the request of FCS. In addition, distributing agencies would be required to notify FCS of the information as the agreement changes. The Department's authority under §§ 3015.124(a) and 3016.43 to terminate agreements for cause would not be affected by this proposed change. Furthermore, the availability of funds and commodities beyond those amounts available at the time the ''permanent'' agreements are signed is dependent upon future Congressional appropriations and FCS's annual decision to continue the agreement.

With regard to annual agreements between distributing and recipient agencies, the Department recognizes the need for a relaxation of the paperwork burden, and proposes to amend § 250.12(b) to provide for permanent agreements between distributing agencies and recipient agencies, with amendments to be made as necessary. Distributing agencies must ensure that recipient agencies provide, on a timely basis, by amendment to the agreement, any information on changes in program administration, including, but not limited to, changes in site locations, number of meals or needy persons to be served, or changes resulting from amendments to Federal regulatory requirements and policy. Because of the nature of, and volatility in costs of, services provided by carriers, and by subdistributing agencies that are not recipient agencies (i.e., do not distribute donated foods to eligible recipients or utilize foods to provide services to those eligible), the Department believes that agreements between distributing agencies and these entities should remain one year, with an option for two one-year extensions. The proposed restructuring of § 250.12 to detail the different duration requirements for agreements between distributing agencies and the various types of local entities is described below.

The Department agrees that contracts of longer duration between State agencies and storage facilities would reduce the paperwork burden. Such contracts would also be attractive to storage facilities, as they would not have to bid so frequently for a new contract. Furthermore, longer contracts would provide more time to amortize expenses incurred in ensuring a high quality of service. Therefore, to provide distributing agencies with maximum flexibility in contracting for storage facilities, the Department proposes to amend § 250.14(d) to extend the contract period to be effective for no longer than five years, including option years. Thus, distributing agencies may choose to negotiate contracts for a five-year, or three-year, period, or for one year with option years not exceeding four, etc. This flexibility will enable State agencies to enter into contracts of whatever duration in their estimation will yield the best combination of quality service and cost, subject only to the five-year maximum. This rule also proposes to make some technical changes in paragraphs (d) and (e) of § 250.14 by revising some incorrect references.

Under current regulations, food service management companies may be employed to conduct the food service operations of charitable institutions, nonprofit summer camps for children, nutrition programs for the elderly, schools, nonresidential child care institutions, and service institutions receiving donated foods. The duration of contracts between these companies and charitable institutions, nonprofit summer camps for children, and nutrition programs for the elderly is limited, in § 250.12(c), to one year, with an option for two additional one-year periods. Section 210.16(d) sets the duration of contracts between school food authorities, which administer school nutrition programs, and food service management companies at one year, with an option for four additional one-year periods. Although the commenters to the 1990 Notice did not address agreements with food service management companies, this rule proposes, in the interest of reducing the paperwork burden, to revise § 250.12(c) to make contracts between these companies and charitable institutions, nonprofit summer camps for children, and nutrition programs for the elderly, of the same maximum duration as those between food service management companies and school food authorities. As part of the proposed revision of this section, paragraph (2), addressing the length of time that records shall remain available, would be removed, as recordkeeping requirements will be established for all entities contracting with distributing, subdistributing, or recipient agencies in § 250.16.

This rule proposes to restructure § 250.12 so as to more clearly state the duration requirements for all food distribution program agreements, as described above. The restructuring entails the revision of § 250.12(b) to describe the terms and conditions of distributing agency agreements with recipient agencies, subdistributing agencies, carriers, and other entities, and the creation of a new § 250.12(c) to address the duration of such agreements. §§ 250.12(c), 250.12(d), and 250.12(e) would be redesignated as §§ 250.12(d), 250.12(e), and 250.12(f), respectively. In conformance with the restructuring of § 250.12, this rule proposes to delete reference to § 250.12(c) and insert instead reference to § 250.12(d) in the following §§ 250.3, in the definition of ''food service management company''; 250.19(b)(1)(iv); 250.40(a)(4); 250.41(a)(3); 250.42(a); 250.48(a)(1); and, 250.49(a). Additionally, this rule proposes to make a technical change in the redesignated § 250.12(e), which addresses storage facility contracts, by replacing the incorrect reference to § 250.14(c) (''Reviews'') with a reference to § 250.14(d) (''Contracts'').

Collection and Submission of Commodity Acceptability Information

7 CFR 250.13(k)(1) currently requires that State agencies obtain information from recipient agencies which reflects: (1) The types and forms of donated foods that are most useful to recipients; (2) commodity specification recommendations; and (3) requests for options regarding package sizes and forms of commodities. Paragraph (k)(2) of this Section lists the categories of recipient agencies from which State agencies are to obtain this information; paragraph (k)(3) stipulates that this information be submitted to FCS on an annual basis, utilizing form FCS–663.

Historically, USDA has donated a steady, dependable supply of foods acquired under the Commodity Credit Corporation's price-support operations to a variety of outlets, including charitable institutions and nonprofit summer camps for children. These donated foods have included cereal and grain products such as flour, cornmeal, rice, rolled wheat and oats, bulgur, macaroni, and spaghetti; peanut and oil products, such as roasted peanuts, peanut butter, peanut granules, soybean oil, and soybean shortening; and dairy products. However, due to the significant amounts of these foods that were distributed to recipient agencies in the past, changes in price-support legislation, and changes in agricultural market conditions, the inventories of available donated foods have been greatly reduced. At the present time, Federal inventories of surplus commodities are insufficient to supply food distribution programs on a regular basis.

While donated foods may also become available to charitable institutions and nonprofit summer camps for children through surplus-removal actions, their availability cannot be assured, and the types of commodities available can be expected to vary significantly over time.

Because of the variety in the types and forms of donated foods previously available on an ongoing basis to charitable institutions and nonprofit summer camps for children, the Department applied to these institutions the regulatory requirement for annual collection and reporting of commodity acceptability information. However, since surplus commodities are not currently available to these institutions on a regular basis, the Department has determined that collection of commodity acceptability information from them no longer serves a useful purpose.

For the same reasons, surplus commodities are also no longer available in TEFAP on a regular basis. Although, since 1989, commodities have been purchased, under authority of the Emergency Food Assistance Act of 1983 (Pub. L. 98–8; 7 U.S.C. 7501–16), to supplement the distribution of the dwindling surplus foods to needy households, the amount of funds appropriated for commodity purchases in TEFAP has been greatly reduced in recent years. Since the foods from which States may select for distribution to TEFAP households are the same as those available for distribution to eligible households in CSFP or FDPIR, the Department believes that it is not necessary to require State agencies to submit separate commodity acceptability reports for TEFAP.

USDA regulations (7 CFR 250.13(k)) also presently require that commodity acceptability information for SFSP be submitted. However, because the target group is the same as that for the National School Lunch and School Breakfast Programs (which are included in the legislative requirement), and because the donated foods provided are the same, or similar, to donated foods provided in those programs, the Department considers the collection and submission of commodity acceptability information for recipient agencies participating in SFSP to be redundant.

The Commodity Distribution Reform Act and WIC Amendments of 1987 (Pub. L. 100–237; 7 U.S.C. 612c note) provides the basis for the Department's regulations requiring the collection of commodity acceptability information from recipient agencies. Section 3(a)(1)(B) of Pub. L. 100–237 provides that this data must be utilized by the Department in determining the types and forms of foods to be purchased for certain food distribution programs. The law does not, however, specifically include SFSP or nonprofit summer camps for children among those recipient agencies from which such information must be obtained. Additionally, the law requires the collection and use of commodity acceptability information only to the extent practicable for TEFAP, and for the donation of foods to charitable institutions. Therefore, as part of the Department's effort to reduce the paperwork burden, and for the reasons discussed above, this rule proposes to revise § 250.13(k)(2) to exclude SFSP, summer camp, TEFAP, and charitable institution recipient agencies from those for which distributing agencies are required to submit commodity acceptability information. Such distributing agencies may still choose to collect and submit to FCS information on commodity acceptability from these categories of recipient agencies, and all such submissions would be carefully reviewed by FCS.

In conformance with the above proposals, this rule also proposes to amend § 250.13(k)(3) to delete reference to the annual submission by November 30th of commodity acceptability reports for summer camps and SFSP (for which reports would not be required), and to clarify that distributing agencies must submit commodity acceptability reports (for those programs for which reports would be required, as stipulated in § 250.13(k)(2)) to FCS Regional Offices by April 30th each year. Additionally, this rule proposes to make a technical change to § 250.24(d)(1) by removing the word ''semi-annual'' to reflect the current requirement contained in section 3(f)(2) of Pub. L. 100–237, as amended, which mandates the annual collection of commodity acceptability information. This statutory change was addressed in a final rule published in the Federal Register on July 22, 1993 (58 CFR 39113).

Submission of Inventory Reports

As previously described in this Preamble, most distributing agencies report excessive inventories of donated foods on the revised FCS–155, the Inventory Management Register, while distributing agencies administering FDPIR and CSFP use the more detailed inventory reports, forms FCS–152 (FDPIR) and FCS–153 (CSFP), to submit data on program participation, commodity distribution to households, and inventory levels. This rule proposes to revise the language in § 250.17(a) to accurately describe the reporting function of FCS–155, which now requires reporting of excessive inventories only, and to require semiannual submission of this form, instead of monthly submissions, unless FCS determines that (a) more frequent reporting is necessary to maintain program accountability, or (b) less frequent reporting is sufficient to meet program needs. Reference would continue to be made to the submission of the FCS–155, or ''other format approved by FCS''—the other currently approved formats being, of course, forms FCS–152 and FCS–153, utilized in FDPIR and CSFP, respectively. Lastly, we propose to delete reference to a list of individual food orders received for each food item delivered (the function of the FCS–155A, which has been found to be unnecessary, as discussed above).

Monitoring Requirements for Charitable Institutions and Summer Camps

7 CFR 250.19(b) requires State agencies to establish review procedures to ensure compliance with Federal regulations addressing household eligibility, food ordering and storage, inventory controls, reporting and recordkeeping requirements, and civil rights provisions. Section 250.19(b)(1)(i) presently requires State agencies to conduct on-site reviews of each participating charitable institution, nonprofit summer camp for children, and nutrition program for the elderly at least once every four years, with at least 25 percent of the total number of such institutions reviewed each year. Section 250.19(b)(1)(iv) requires biennial reviews of all food service management companies under contract with recipient agencies that have agreements with distributing agencies. Because of the reduced availability of USDA commodities for charitable institutions and nonprofit summer camps for children, as discussed in detail above, the Department believes that the requirements governing monitoring reviews for these recipient agencies, as well as the food service management companies under contract with them, are excessive. Thus, the Department proposes in this rule to revise § 250.19(b)(1)(i) to require that State agencies perform on-site reviews of charitable institutions, nonprofit summer camps for children, and the food service management companies under contract with them, at a minimum: (1) whenever the State agency identifies actual or probable deficiencies in program administration through audits, investigations of complaints, reports submitted by recipient agencies, or any other information available to the State agency which, at the discretion of the State agency, warrants an on-site review; or, (2) at the request of FCS. State agencies are encouraged to conduct more frequent reviews as resources and work schedules permit. Section 250.19(b)(1)(iv) is proposed to be revised to note the exception of food service management companies under contract with charitable institutions and nonprofit summer camps for children from the biennial review requirement for food service management companies under contract with other types of recipient agencies.

FCS Instruction 113–3, ''Civil Rights Compliance and Enforcement—Food Distribution Programs,'' presently includes an on-site review requirement of recipient agencies every five years to ensure compliance with civil rights regulations. In accordance with the above proposed change in on-site review requirements for charitable institutions and nonprofit summer camps for children, this provision of the instruction would be removed. The revised instruction would require that on-site reviews to ensure compliance with civil rights provisions be conducted under conditions, and at the frequency, established by Federal regulations for the various types of recipient agencies. While the proposed rule relaxes on-site review requirements, distributing, subdistributing, and recipient agencies would be required to continue to comply with all other provisions in Federal regulations and FCS Instruction 113–3, including the collection of racial/ethnic participation data, to ensure that discrimination because of race, color, national origin, age, sex, or handicap does not occur in the operation of food distribution programs.

This rule also proposes to restructure § 250.19(b)(1) to address in separate subparagraphs nutrition programs for the elderly, on the one hand, and charitable institutions and nonprofit summer camps for children, on the other, because of the different monitoring requirements that would result from adoption of the proposal described above. In addition, this rule proposes to make a technical change in § 250.19(b)(1)(i) by deleting the incorrect reference to § 250.14(a) (''Standards for Warehousing and Distribution Systems'') and inserting instead reference to § 250.14(b) (''Standards for Storage Facilities'').

The Emergency Food Assistance Program (7 CFR Part 251)

Duration Requirements for Agreements with Distributing and Recipient Agencies

Section 251.2(c) of the regulations requires that distributing agencies enter into an agreement with the Department for the receipt of TEFAP foods and Federal funds for administrative costs. In addition to entering into agreements with the Department, distributing agencies are also required to enter into agreements with eligible emergency feeding organizations (EFOs). As stated in § 251.4(a), Part 250 applies to the administration of TEFAP, to the extent that it is not inconsistent with Part 251. While the duration requirements for these types of agreements are not stipulated under this Part, 7 CFR 250.12(b) limits the length of such agreements to one year. The provisions contained in § 251.2(c) also require that distributing agencies enter into agreements with EFOs that receive Federal funds and that such agreements be limited to one year, with an option for renewal for two one-year periods.

As discussed in detail above, commenters recommended that Federal-State agreements be made ongoing in order to reduce the paperwork burden. The Department concurs with this recommendation, and proposes to amend § 251.2(c) to make TEFAP Federal-State agreements permanent, with amendments to be made at the request of FCS, and to make agreements between distributing agencies and EFOs permanent, with amendments to be made as necessary. In addition, distributing agencies must ensure that EFOs provide, on a timely basis, by amendment to the agreement, any changed information, including any changes resulting from amendments to Federal regulations or policy. Such information must include, but not be limited to, changes in the number of distribution sites and their locations, number of needy persons to be served, frequency of distributions, household eligibility criteria to be used in certifying households, and allocation of TEFAP administrative funds.

Submission of Inventory Reports

This rule proposes to amend § 251.10(d)(2) to direct State agencies to adhere to the inventory reporting requirements stipulated in § 250.17(a), since State agencies administering TEFAP will also utilize the revised form FCS–155, the Inventory Management Register, to report excessive commodity inventories. Household participation data will also continue to be reported utilizing this form, at the same frequency that inventory information is reported. This rule proposes to include this requirement in the final sentence of § 251.10(d)(2), and to delete § 251.10(d)(3), which presently addresses this requirement, for both State agencies and EFOs. It will be up to each State agency to determine how best to collect the necessary information from the EFOs. Additionally, this rule proposes to amend § 251.10(a)(1) to remove reference to the obsolete § 250.6(r), and to refer to § 250.16 instead.

Food Distribution Program on Indian Reservations (7 CFR Part 253)

Plan of Operation

Section 253.5(a) of the regulations requires that the State agency (including Indian Tribal Organizations acting as the State agency) responsible for the administration of the Food Distribution Program on Indian Reservations submit a plan of operation each year to FCS for approval. The provisions in this section require that such plans contain a description of the storage and distribution facilities to be utilized, the method of assuring that only eligible households receive benefits, and other information relative to the administration of the program.

Although the commenters did not recommend a change to the requirement that State agencies submit a plan of operation to FCS each year, the Department believes that, because the plan's contents do not change much from year to year, the plan should be permanent, with amendments added as changes in program administration are made. Thus, this rule proposes to amend § 253.5(a) to make the plan of operation permanent, with amendments to be added as: (a) changes in State agency administration of the program, as described in the plan, are made; or, (b) at the request of FCS, e.g., in response to changes in State agency plan requirements or guidance. The Department's authority under §§ 3015.124(a) and 3016.43 to terminate agreements for cause would not be affected by this proposed change.

Application for Federal Assistance

State agencies and Indian Tribal Organizations must continue to submit an application to receive Federal administrative funds on an annual basis, as required by § 253.9(c). However, this rule proposes to amend this section of the regulations to reflect the fact that this application is now made through completion of standard form SF–424, which is mandated by 7 CFR Part 3016 (''Uniform Administrative Requirements for Grants and Cooperative Agreements to State and Local Governments''), instead of form AD–623. This rule also proposes to delete the statement in this section encouraging Indian Tribal Organizations which act as State agencies to first submit applications through the State clearinghouse, as agencies of State government are required to do under 7 CFR Part 3015 (Uniform Federal Assistance Regulations), Subpart V. The Department does not believe that this statement is in the spirit of the Presidential directive of April 29, 1994 (''Government-to-Government Relations with Native American Tribal Governments,'' 59 FR 22951, May 4, 1994), which encourages agencies of the Federal government to work directly with Native American Tribal Governments.

List of Subjects

7 CFR Part 250

Aged, Agricultural commodities, Business and industry, Food assistance programs, Food donations, Food processing, Grant programs-social programs, Indians, Infants and children, Price support programs, Reporting and recordkeeping requirements, School breakfast and lunch programs, Surplus agricultural commodities.

7 CFR Part 251

Aged, Agricultural commodities, Business and industry, Food assistance programs, Food donations, Grant programs-social programs, Indians, Infants and children, Price support programs, Reporting and recordkeeping requirements, School breakfast and lunch programs, Surplus agricultural commodities.

7 CFR Part 253

Administrative practice and procedure, Food assistance programs, Grant programs, Social programs, Indians, Reporting and recordkeeping requirements, Surplus agricultural commodities.

Accordingly, 7 CFR parts 250, 251, and 253 are proposed to be amended as follows.

PART 250—DONATION OF FOODS FOR USE IN THE UNITED STATES, ITS TERRITORIES AND POSSESSIONS AND AREAS UNDER ITS JURISDICTION

1. The authority citation for part 250 continues to read as follows:

Authority: 5 U.S.C. 301; 7 U.S.C. 612c, 612c note, 1431, 1431b, 1431e, 1431 note, 1446a-1, 1859, 2014, 2025; 15 U.S.C. 713c; 22 U.S.C. 1922; 42 U.S.C. 1751, 1755, 1758, 1760, 1761, 1762a, 1766, 3030a, 5179, 5180.

§§ 250.3, 250.19, 250.40, 250.41, 250.42, 250.48, 250.49 [Amended]

2. In § 250.3, in the definition of *Food service management company*, and in §§ 250.19(b)(1)(iv), 250.40(a)(4), 250.41(a)(3), 250.42(a), 250.48(a)(1), and 250.49(a), the citation ''250.12(c)'' is removed wherever it appears, and the citation ''250.12(d)'' is added in its place.

3. In Section 250.12:

a. The third and fourth sentences of paragraph (a) are revised;

b. The concluding text of paragraph (b) is removed;

c. Paragraphs (c), (d), and (e) are redesignated as paragraphs (d), (e) and (f), and a new paragraph (c) is added; and

d. Newly redesignated paragraphs (d) and (e) are revised.

The revisions and addition read as follows:

§ 250.12 Agreements and contracts.

(a) *Agreements with Department.* * * * The agreements shall be considered permanent, with amendments to be made at the request of FCS. In addition, agreements between the Department and State Agencies on Aging that elect to receive cash in lieu of commodities shall also be considered permanent, with amendments to be made at the request of FCS.

* * * * *

(c) *Duration of distributing agency agreements.*—(1) *Recipient agencies.* Distributing agency agreements with recipient agencies shall be considered permanent, with amendments to be made as necessary. Distributing agencies shall ensure that recipient agencies provide, on a timely basis, by amendment to the agreement, any changed information, including, but not limited to, any changes resulting from amendments to Federal regulatory requirements and policy and changes in site locations, and number of meals or needy persons to be served.

(2) *Subdistributing agencies, carriers, and other entities.* Distributing agency agreements with subdistributing agencies that are not recipient agencies, carriers, and other entities shall be in effect for not longer than one year, and shall provide that they may be extended at the option of both parties for two additional one-year periods. The party contracting with the distributing agency shall update all pertinent information and demonstrate that all donated food received during the period of the previous agreement has been accounted for, before an agreement is extended.

(3) *Termination of agreements.* Agreements may be terminated for cause by either party upon 30 days notice.

(d) *Food service management company contracts.* Food service management companies may be employed to conduct the food service operations of nonprofit summer camps for children, charitable institutions, nutrition programs for the elderly, schools, nonresidential child care institutions, and service institutions. In instances when a food service management company is employed to provide such services, the recipient agency shall enter into a written contract with the food service management company. The contract shall expressly provide that any donated foods received by the recipient agency and made available to the food service management company shall be utilized solely for the purpose of providing benefits for the employing agency's food service operation, and it shall be the responsibility of the recipient agency to demonstrate that the full value of all donated foods is used solely for the benefit of the recipient agency. All food service management companies shall be subject to review by the distributing agency for compliance with contractual requirements, in accordance with § 250.19(b)(1). In the case of nonprofit summer camps for children, charitable institutions, and nutrition programs for the elderly, the contract shall be in effect for no longer than one year, and may provide that it be extended at the option of both parties for not more than four additional one-year periods. Contracts shall provide that they may be terminated for cause by either party upon 30 days notice. Prior to extension of the contract, the nonprofit summer camp for children, charitable institution, or nutrition program for the elderly shall update all pertinent information and demonstrate that all donated food received during the previous contract period has been accounted for.

(e) *Storage facility contracts.* When contracting for storage facilities, distributing agencies and subdistributing agencies shall enter into a written contract, in accordance with § 250.14(d).

* * * * *

4. In § 250.13:

a. Paragraph (k)(2) is amended by removing the words ''the Summer Food Service Program'', ''charitable institutions, summer camps,'' and '', and the Emergency Food Assistance Program''; and by adding ''and'' before ''the Food Distribution Program on Indian Reservations''; and

b. Paragraph (k)(3) is revised to read as follows:

§ 250.13 Distribution and control of donated foods.

* * * * *

(k) * * *

(3) *Timeframes for submission.* Distributing agencies shall submit commodity acceptability reports to the appropriate FCSRO by April 30th of each year on form FCS–663.

5. In § 250.14:

a. The introductory text of paragraph (d) is amended by removing the first three sentences, and adding two new sentences in their place;

b. Paragraph (d)(1) is amended by removing the reference to ''paragraph (a)'' and adding in its place a reference to ''paragraph (b)''; and

c. Paragraph (e) is amended by removing the citation ''§ 250.14(b)'' in the first sentence, and adding in its place a reference to ''paragraph (c) of this section''; and, by removing the reference to ''paragraph (e)'' in the fourth sentence, and adding in its place a reference to ''paragraph (f)''.

The additions read as follows:

§ 250.14 Warehousing, distribution and storage of donated foods.

* * * * *

(d) *Contracts.* When contracting for storage facilities, distributing agencies and subdistributing agencies shall enter into written contracts to be effective for no longer than five years, including option years extending a contract. Before the exercise of option years, the storage facility shall update all pertinent information and demonstrate that all donated foods received during the previous contract period have been accounted for. * * *

* * * * *

6. Section 250.17 is amended by revising paragraph (a) to read as follows:

§ 250.17 Reports.

(a) *Inventory reports and receipt of donated foods.* Distributing agencies shall complete and submit to the FCSRO semiannual reports regarding excessive inventories (as defined in § 250.14(f)) of donated foods, utilizing form FCS–155, the Inventory Management Register, except that distributing agencies shall submit monthly inventory information on form FCS–152, for the Food Distribution Program on Indian Reservations, and on form FCS–153, for the Commodity Supplemental Food Program. FCS may require the use of other reporting formats. FCS may also require that form FCS–155 be submitted more frequently than semiannually if necessary to maintain program accountability, and that any inventory report be submitted less frequently if sufficient to meet program needs. Reports shall be submitted not later than 30 calendar days after the last month in the reporting period as established by FCS.

* * * * *

7. In § 250.19:

a. Paragraph (b)(1)(i) is revised;

b. Paragraphs (b)(1)(ii), (b)(1)(iii), and (b)(1)(iv) are redesignated as paragraphs (b)(1)(iii), b(1)(iv), and b(1)(v), respectively;

c. A new paragraph (b)(1)(ii) is added; and,

d. Newly redesignated paragraph (b)(1)(v) is revised.

The revisions and addition read as follows:

§ 250.19 Reviews.

* * * * *

(b) *Responsibilities of distributing agencies.*

(1) * * *

(i) An on-site review of all nutrition programs for the elderly under agreement in accordance with § 250.12(b), at least once every four years, with not fewer than 25 percent of these programs being reviewed each year. These reviews shall also include on-site reviews of the storage facilities of sites receiving donated foods to ensure compliance with § 250.14(b);

(ii) An on-site review of all charitable institutions and nonprofit summer camps for children under agreement in accordance with § 250.12(b), and the food service management companies under contract with these recipient agencies in accordance with § 250.12(d), at a minimum, whenever the distributing agency identifies actual or probable deficiencies in program administration, including compliance with civil rights provisions, through audits, investigations of complaints, reports submitted by recipient agencies, or any other information available to the State agency which, at the discretion of the State agency, warrants an on-site review, or at the request of FCS;

* * * * *

(v) A biennial review of all food service management companies under contract with recipient agencies in accordance with § 250.12(d), except that:

(A) Food service management companies under contract with charitable institutions and nonprofit summer camps for children shall be reviewed in accordance with paragraph (b)(1)(ii) of this section; and,

(B) Food service management companies under contract with schools participating in the National School Lunch Program or commodity schools under part 210 of this chapter, or with schools participating in the School Breakfast Program under part 220 of this chapter, shall be reviewed in accordance with the provisions set forth in parts 210 and 220.

* * * * *

§ 250.24 [Amended]

8. In § 250.24, paragraph (d)(1) is amended by removing the word ''semi-annual''.

PART 251—THE EMERGENCY FOOD ASSISTANCE PROGRAM

1. The authority citation for part 251 is revised to read as follows:

Authority: 7 U.S.C. 7501–7516.

2. Section 251.2 is amended by revising paragraph (c) to read as follows:

§ 251.2 Administration.

* * * * *

(c) Each State agency that distributes donated foods to emergency feeding organizations or receives payments for storage and distribution costs in accordance with § 251.8 shall perform those functions pursuant to an agreement entered into with the Department. This agreement shall be considered permanent, with amendments to be made at the request of FCS. Such State agencies shall enter into a written agreement with eligible emergency feeding organizations. This agreement shall provide that emergency feeding organizations agree to operate the program in accordance with the requirements of this part, and, as applicable, Part 250 of this chapter. The agreement shall be considered permanent, with amendments to be made as necessary. State agencies shall ensure that emergency feeding organizations provide, on a timely basis, by amendment to the agreement, any information on changes in program administration, including, but not limited to, any changes resulting from amendments to Federal regulations or policy.

3. In § 251.10:

a. Paragraph (a)(1) is amended by removing the citation ''§ 250.6(r)'' and adding in its place the citation ''§ 250.16'';

b. Paragraph (d)(2) is revised to read as follows; and

c. Paragraph (d)(3) is removed.

§ 251.10 Miscellaneous provisions.

* * * * *

(d) *Reports.* * * *

(2) Each State agency shall complete and submit to the FCSRO reports to ensure that excessive inventories of donated foods are not maintained, in accordance with the requirements of § 250.17(a) of this chapter. Such reports shall also include the total number of households served in the State since the previous report submittal, based upon current information received from emergency feeding organizations.

* * * * *

PART 253—ADMINISTRATION OF THE FOOD DISTRIBUTION PROGRAM FOR HOUSEHOLDS ON INDIAN RESERVATIONS

1. The authority citation for part 253 continues to read as follows:

Authority: 91 Stat. 958 (7 U.S.C. 2011–2027), unless otherwise noted.

2. Section 253.5 is amended by removing the first two sentences of the introductory text of paragraph (a)(1) and adding, in their place, three new sentences to read as follows:

§ 253.5 State agency requirements.

(a) *Plan of operation.* (1) The State agency that assumes responsibility for the Food Distribution Program shall submit a plan of operation for approval by FCS. Approval of the plan shall be a prerequisite to the donation of commodities available for use by households under § 253.9. The approved plan shall be considered permanent, with amendments to be added as changes in State agency administration or management of the program, as described in the plan, are made, or at the request of FCS. * * *

* * * * *

3. Section 253.9 is amended by revising paragraph (c)(1) to read as follows:

§ 253.9 Administrative funds for State agencies.

* * * * *

(c) *Application for funds.* (1) Any State agency administering a Food Distribution Program that desires to receive administrative funds under this section shall submit form SF–424, ''Application for Federal Assistance,'' to the appropriate FCS Regional Office at least three months prior to the beginning of a Federal fiscal year. The application shall include budget information, reflecting by category of expenditure the State agency's best estimate of the total amount to be expended in the administration of the program during the fiscal year. FCS may require that detailed information be submitted by the State agency to support or explain the total estimated amounts shown for each budget cost category. As required by 7 CFR 3015, Subpart V, agencies of State government shall submit the application for Federal assistance to the State clearinghouse before submitting it to the FCSRO. ITOs shall not be subject to this requirement.

* * * * *

Dated: March 10, 1997.

William E. Ludwig,

Administrator.

[FR Doc. 97–6427 Filed 3–13–97; 8:45 am]

BILLING CODE 3410–30–U

Food Safety and Inspection Service

9 CFR Part 318

[Docket No. 95–052P]

RIN 0583–AC02

Use of Sorbitol in Cooked Roast Beef Products

AGENCY: Food Safety and Inspection Service, USDA.

ACTION: Proposed rule.

SUMMARY: The Food Safety and Inspection Service (FSIS) is proposing to amend the Federal meat inspection regulations to add cooked roast beef products to the list of products in which sorbitol is permitted. FSIS proposes this action in response to a petition requesting that FSIS allow the use of sorbitol, both to sweeten and to reduce charring in cooked roast beef products, at the level of up to 2 percent of the product formulation. The sorbitol would be added to a solution of ingredients that are pumped into the beef prior to cooking.

DATES: Comments must be received on or before May 13, 1997.

ADDRESSES: Send an original and two copies of written comments to: FSIS Docket Clerk, Docket ι95–052P, Room 3806, South Agriculture Building, 1400 Independence Avenue, SW., Washington, DC 20250–3700. Reference material cited in this document and any comments received in response to this proposal will be available for public inspection in the FSIS Docket Room from 8:30 a.m. to 1:00 p.m., and from 2:00 p.m. to 4:30 p.m., Monday through Friday.

FOR FURTHER INFORMATION CONTACT: Charles R. Edwards, Director, Product Assessment Division, Regulatory Programs, (202) 418–8900.

SUPPLEMENTARY INFORMATION:

FSIS was petitioned to allow the use of sorbitol in cooked roast beef products in the amount currently approved for use in other meat and meat food products. The petitioner requested that FSIS amend § 318.7(c)(4) of the Federal meat inspection regulations to allow the use of sorbitol both to sweeten and to reduce charring in cooked roast beef products in an amount not to exceed two percent of the product formulation, excluding the formula weight of water or ice. The sorbitol would be added to a solution of ingredients that are pumped into the beef prior to cooking.

Sorbitol is a common sugar alcohol; it can be found in apples, pears, and other foods. About half as sweet as sucrose (i.e., sugar), it is often used as a substitute sweetener in reduced-sugar products such as sugar-free candy and other food products for diabetics. Sorbitol is listed in 21 CFR 184.1835 by the Food and Drug Administration (FDA) as a substance affirmed as generally recognized as safe for use as an anticaking agent, humectant, flavoring agent, and for various other uses, when used in accordance with good manufacturing practices. Sorbitol does not possess the same chemical makeup as do sugars that caramelize, i.e., brown and char in the presence of high heat. It is this characteristic of sorbitol that reduces charring in cooked roast beef products and other meat products in which it is used.

The petitioner conducted informal sensory testing using various levels of sorbitol in roast beef product formulations. Tests were conducted by using informal visual and taste panels. A panel of eight people measured the amount of charring that took place on roast beef products treated with sorbitol by evaluating the browning of products after they were treated and cooked. Another panel of eight measured the sweetness of the products by tasting the test products after they were treated and cooked. The test data show that two percent sorbitol both reduces charring and achieves a suitable level of sweetness.

After reviewing the petitioner's technical data and information, the Administrator, FSIS, determined that the technical data and information submitted with the petition demonstrated the efficacy of sorbitol for these uses at the level not to exceed two percent of product formulation.

The Administrator determined that these uses of sorbitol (1) will not render the product adulterated or misbranded, or otherwise not in compliance with the requirements of the Federal Meat Inspection Act and (2) is functional and suitable for the product, and is permitted at the lowest level necessary to accomplish the stated effect. To permit these uses of sorbitol, the chart of approved substances in the meat inspection regulations (9 CFR 318.7(c)(4)) must be amended.

FSIS published a direct final rule in the Federal Register on February 27, 1996 (61 FR 7207), that would have added new uses of sorbitol both to sweeten and to reduce charring in cooked roast beef products up to a level of two percent of the product formulation.

FSIS solicited comments concerning the direct final rule for a 30-day period ending March 28, 1996. FSIS stated that the effective date of the proposed amendment would be 60 days after publication of the direct final rule in the Federal Register, unless the Agency received written adverse comments or a notice of intent to submit adverse comments by the close of the comment period. FSIS also stated that if it received written adverse comments or a notice of intent to submit adverse comments, it would publish a document in the Federal Register withdrawing the direct final rule before the scheduled effective date and would publish a proposed rule for public comment.

On April 16, 1996 (61 FR 16617), FSIS withdrew the direct final rule because it received one adverse comment from a consumer who opposed adding cooked roast beef to the list of products in which sorbitol is permitted. The comment contended that, while sorbitol is generally recognized as safe, increasing numbers of people have reactions to ingredients ''hidden in prepared foods.'' The currently permitted use of this substance, as specified in the regulations, complies with applicable requirements of the Food and Drug Administration (FDA). Its proposed use in roast beef would also be in compliance with those requirements, as are current allowances for cured pork products and sausages. FSIS is aware of the needs of consumers who are sensitive to certain ingredients and requires the labels of all products under its jurisdiction to convey information that is useful to consumers, including the common or usual names of all ingredients used to make the food. Under this proposal, sorbitol would have to be listed in the ingredients statements of cooked roast beef products as well as in ingredients statements of the other products in which it is already permitted. This listing would provide sufficient information to consumers who are sensitive to sorbitol or who have other reasons for selecting sorbitol-free products. Therefore, FSIS is proposing to amend the chart of approved substances in 9 CFR 318.7 (c)(4) to add the use of sorbitol both to sweeten and to reduce charring in cooked roast beef products at a level of up to two percent of product formulation.

Executive Order 12988

This proposed rule has been reviewed under Executive Order 12988, Civil Justice Reform. If this proposed rule is adopted: (1) all state and local laws and regulations that are inconsistent with this rule will be preempted; (2) no retroactive effect will be given to this rule; and (3) administrative proceedings will not be required before parties may file suit in court challenging this rule.

Executive Order 12866 and Regulatory Flexibility Act

This proposed rule has been determined to be not significant and has not been reviewed by the Office of Management and Budget.

The Administrator has made an initial determination that this proposed rule would not have a significant economic impact on a substantial number of small entities, as defined by the Regulatory Flexibility Act (5 U.S.C. 601). The proposed rule would permit the use of sorbitol to sweeten and to reduce charring in cooked roast beef products. The sorbitol would be added to a solution of ingredients that are pumped into the beef prior to cooking. This amendment would provide cooked roast beef processors with an additional, alternative substance that can be used to sweeten their product while at the same time to reduce charring that may occur during the cooking process. The use of sorbitol to sweeten and to reduce charring in cooked roast beef products would be voluntary. Small manufacturers opting to use sorbitol for these purposes would be required to revise their product labels. Decisions by individual manufacturers on whether to do so would be based on their conclusions that the benefits outweigh the costs.

Paperwork Requirements

Abstract: FSIS has reviewed the paperwork and recordkeeping requirements in this proposed rule in accordance with the Paperwork Reduction Act. This rule would require manufacturers opting to use sorbitol to sweeten and to reduce charring in cooked roast beef products to revise their product labels and submit such labeling to FSIS for approval.

Estimate of Burden: Establishments would have to develop product labels in accordance with the proposed rule. To receive approval of the labels, establishments would complete FSIS Form 7234–1. FSIS program employees would review FSIS Form 7234–1 to ensure that information on the labels complies with the regulations. FSIS estimates that it would take 60 minutes to design and develop modified product labels in accordance with the proposed regulation and 15 minutes to prepare FSIS Form 7234–1 and submit it, along with the label, to FSIS or to a label expediter who would deliver the form and label to FSIS.

Respondents: Meat establishments.

Estimated Number of Respondents: 315 meat establishments.

Estimated Number of Responses per Respondent: FSIS estimates that each establishment would modify about 2 product labels.

Estimated Total Annual Burden on Respondents: 788 hours.

Copies of this information collection assessment can be obtained from Lee Puricelli, Paperwork Specialist, Food Safety and Inspection Service, USDA, Room 3812, South Agriculture Building, Washington, DC 20250–3700.

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 will have practical utility; (b) 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; (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 those who are to respond, including through use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology. Send comments to both Lee Puricelli, Paperwork Specialist, at the address provided above, and the Desk Officer for Agriculture, Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20253.

Comments are requested by May 13, 1997. To be most effective, comments should be sent to OMB within 30 days of the publication date of this proposed rule.

List of Subjects in 9 CFR Part 318

Food additives, Meat inspection.

For the reasons discussed in the preamble, FSIS is proposing to amend 9 CFR part 318 of the Federal meat inspection regulations as follows:

PART 318—ENTRY INTO OFFICIAL ESTABLISHMENTS; REINSPECTION AND PREPARATION OF PRODUCTS

1. The authority citation for part 318 would be revised to read as follows:

Authority: 7 U.S.C. 138f, 450, 1901–1906; 21 U.S.C. 601–695; 7 CFR 2.18, 2.53.

2. Section 318.7(c)(4) would be amended by adding to the chart of substances, under the Class of Substance ''Flavoring agents; protectors and developers,'' the substance sorbitol as follows:

§ 318.7 Approval of substances for use in the preparation of products.

* * * * *

(c) * * *

(4) * * *

Class of substance	Substance	Purpose	Products	Amount
*	*	*	* *	* *
Flavoring agents; protectors and developers.	Sorbitol ..	To flavor, to facilitate the removal of casings from product, and to reduce caramelization and charring.	As provided in part 319 of this subchapter, cooked roast beef, cured pork products, and cooked sausage labeled frankfurter, frank, furter, wiener, and knockwurst.	Not to exceed 2 percent of the weight of the formula, excluding the formula weight of water or ice, when used in accord-ance with 21 CFR 184.1835.
*	*	*	* *	* *

Done at Washington, DC, on March 7, 1997.

Thomas J. Billy,

Administrator.

[FR Doc. 97–6447 Filed 3–13–97; 8:45 am]

BILLING CODE 3410–DM–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 25

[Docket No. NM–138, Notice No. SC–97–1–NM]

Special Conditions: Jetstream Aircraft Limited Model 4101 Airplane; Continuous Power Reserve (CPR) System

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed special conditions.

SUMMARY: This notice proposes special conditions for the Jetstream Aircraft Limited Model 4101 airplane. This airplane will have a novel or unusual design feature associated with installation of the CPR system. This notice contains the additional safety standards that the Administrator considers necessary to establish a level of safety equivalent to that established by the airworthiness standards of part 25 of the FAR.

DATES: Comments must be received on or before April 28, 1997.

ADDRESSES: Comments on this proposal may be mailed in duplicate to: Federal Aviation Administration, Office of the Assistant Chief Counsel, Attention: Rules Docket (ANM–7), Docket No. NM–138, 1601 Lind Avenue SW, Renton, Washington 98055–4056; or delivered in duplicate to the Office of the Assistant Chief Counsel at the above address. Comments must be marked: Docket No. NM–138. Comments may be inspected in the Rules Docket weekdays, except Federal holidays, between 7:30 a.m. and 4:00 p.m.

FOR FURTHER INFORMATION CONTACT: William Schroeder, FAA, Standardization Branch, ANM–113, Transport Airplane Directorate, Aircraft Certification Service, 1601 Lind Avenue SW, Renton, Washington 98055–4056; telephone 206–227–2148; fax 206–227–1149.

SUPPLEMENTARY INFORMATION:

Comments Invited

Interested persons are invited to participate in the making of these proposed special conditions by submitting such written data, views, or arguments as they may desire. Communications should identify the regulatory docket or notice number and be submitted in duplicate to the address specified above. All communications received on or before the closing date for comments will be considered by the Administrator before futher rulemaking action on this proposal is taken. The proposals contained in this notice may be changed in light of the comments received. All comments received will be available, both before and after the closing date for comments, in the Rules Docket for examination by interested parties. A report summarizing each substantive public contact with FAA personnel concerning this rulemaking will be filed in the docket. Commenters wishing the FAA to acknowledge receipt of their comments submitted in response to this notice must include a self-addressed, stamped postcard on which the following statement is made:

''Comments to Docket No. NM–138.'' The postcard will be date stamped and returned to the commenter.

Background

On June 7, 1994, Jetstream Aircraft Limited applied for approval of a design change (without a new airplane model designation) to Type Certificate No. A41NM for the installation of a CPR system on the Jetstream Model 4101 airplane. The Jetstream Model 4101 is a 30 passenger, 23,000 pounds maximum take-off weight, transport category airplane with two Allied Signal TPE331–14GR/HR series turbopropeller engines. The CPR system makes a CPR power rating available for the final take-off climb and en route phases of flight after failure of one engine.

The CPR power rating for this engine installation is equivalent to the maximum continuous power rating established for the engine under Part 33 of the Federal Aviation Regulations (FAR). Following engine failure, the CPR system automatically increases the engine maximum exhaust gas temperature (EGT) limit, which permits the operating engine's maximum continuous power rating to be obtained at higher ambient air temperatures. Increased engine hour and cycle maintenance factors apply for CPR power rating operation. Since the CPR power rating will only be available during engine-out conditions, the maximum power normally available with all engines operating will be less than the part 33 certified maximum continuous power rating at certain higher ambient temperature ranges.

The CPR system is novel when compared to those systems envisaged when the applicable regulations in part 25 were promulgated. Therefore, the airworthiness regulations in part 25 do not contain adequate or appropriate safety standards for airplanes with CPR systems installed. Special conditions are therefore prescribed to supplement the certification basis of record for the Jetstream Model 4101 airplane with a CPR system installed.

Type Certification Basis

Under the provisions of § 21.101, Jetstream Aircraft Limited must show that the Jetstream Model 4101, as changed, continues to meet the applicable provisions of the regulations incorporated by reference in Type Certificate No. A41NM or the applicable regulations in effect on the date of application for the change. The regulations incorporated by reference in the type certificate are commonly referred to as the ''original type certification basis.'' The regulations incorporated by reference in Type Certificate No. A41NM are part 25 of the FAR dated February 1, 1965, as amended by Amendments 25–1 through 25–66. The regulations incorporated by reference also include certain special conditions, exemptions, and later amended sections of Part 25 that are not relevant to these proposed special conditions.

If the regulations incorporated by reference do not provide adequate standards with respect to the change, the applicant must comply with certain regulations in effect on the date of application for the change. The FAA has determined that the areas of the Jetstream Model 4101 that are affected by the installation of the CPR system must also be shown to comply with all sections of part 25 as amended by Amendments 25–1 through 25–81 in effect on the date of application.

If the Administrator finds that the applicable airworthiness regulations (i.e., part 25 as amended) do not contain adequate or appropriate safety standards for the Jetstream Model 4101 because of a novel or unusual design feature, special conditions are prescribed under the provisions of § 21.16. When appropriate, special conditions are issued in accordance with § 11.49 of the FAR after public notice, as required by §§ 11.28 and 11.29(b), and become part of the type certification basis in accordance with § 21.101(b)(2). Special conditions are initially applicable to the model for which they are issued. Should the type certificate for that model be amended later to include any other model that incorporates or should any other model already included on the same type certificate be modified to incorporate the same novel or unusual design feature, the special conditions would also apply to the other model under the provisions of § 21.101(a)(1).

In addition to the applicable airworthiness regulations and special conditions, the Jetstream Model 4101 must comply with the fuel vent and exhaust emission requirements of part 34 and the noise certification requirements of part 36.

Novel or Unusual Design Features

The Jetstream Model 4101 will incorporate a CPR system that provides an engine power rating (as defined on the airplane) that is equivalent to the engine's part 33 certified maximum continuous power rating. Since the CPR power rating will only be available during engine-out conditions, the maximum power available with all engines operating will normally be less than the part 33 certified maximum continuous power rating at certain higher ambient temperatures. The CPR system is integrated into the existing approved Automatic Power Reserve (APR) system. On the Jetstream 4100 airplane, the APR system is equivalent to an Automatic Takeoff Thrust Control System (ATTCS) as defined in Appendix I of Part 25. The currently approved APR system automatically makes additional thermodynamic power and torque available on the operating engine after engine failure during takeoff and for approach climb (go-around). For certain ambient temperature ranges, the proposed CPR system automatically increases the engine's EGT limit and torque available on the operating engine for final take-off climb and en route flight phases after failure of one engine. The CPR-related increased EGT limit, which is above the two-engines-operating EGT maximum continuous power and take-off limits, enables the operating engine to achieve the flat-rated maximum continuous power (torque) level at higher outside air temperature (OAT). Engine operation in the APR and CPR modes requires application of engine hour and cycle maintenance factors as specified in engine Type C Certificate Data Sheet E18NE.

As discussed above, these special conditions are applicable to the Jetstream Model 4101. Should Jetstream Aircraft Limited apply at a later date for a change to the type certificate to include another model incorporating the same novel or unusual design feature, these special conditions would apply to that model as well under the provisions of § 21.101(a)(1).

Conclusion

This action affects only certain novel or unusual design features on one model of airplane. It is not a rule of general applicability, and it affects only the applicant who applied to the FAA for approval of these features on the airplane.

List of Subjects in 14 CFR Part 25

Air transportation, Aircraft, Aviation safety, Safety.

The authority citation for these special conditions is as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701, 44702, 44704.

The Proposed Special Conditions

Accordingly, the Federal Aviation Administration (FAA) proposes the following special conditions as part of the type certification basis for the Jetstream Model 4101 airplane.

Installation of a Continuous Power Reserve (CPR) System

(a) General. With the CPR system functioning normally as designed, all applicable requirements of part 25 must be met without requiring any unusual action (other than arming the system prior to dispatch) by the crew to set power or thrust.

(b) Performance and Reliability Requirements.

(1) A CPR failure or combination of failures.

(i) That prevents the automatic insertion of CPR thrust or power must be shown to be an improbable event;

(ii) That prevents the automatic insertion of APR thrust or power during the critical time interval defined in Appendix I of Part 25 must be shown to be an improbable event; and

(iii) Shall not result in the significant loss or reduction in thrust or power, or must be shown to be an extremely improbable event.

(2) All applicable performance requirements of part 25 must be met with an engine failure occurring at the most critical time with the CPR system functioning.

(c) Thrust Setting. The maximum continuous thrust or power setting specified for use with all engines operating may not be less than any of the following:

(1) Ninety (90) percent of the thrust or power set by the CPR system for which AFM performance credit is approved;

(2) That required to permit normal operation of all safety-related systems and equipment dependent upon engine thrust or power lever position; or

(3) That shown to be free of hazardous engine response characteristics when thrust or power is advanced from the initial all-engines-operating thrust or power setting to the maximum approved maximum continuous/CPR mode thrust or power setting.

(d) Powerplant Controls.

(1) In addition to the requirements of § 25.1141, no single failure or malfunction, or probable combination thereof, of the CPR, including associated systems, may cause the failure of any powerplant function necessary for safety.

(2) The CPR system must be designed to:

(i) In the event of a CPR system failure, permit manual decrease or increase in thrust or power up to the highest maximum continuous thrust or power approved for the airplane under existing conditions through the use of the power lever. For airplanes equipped with limiters that automatically prevent engine operating limits from being exceeded under existing ambient conditions, other means may be used to increase the thrust or power in the event of a CFR failure provided the means is located on or forward of the power levers; is easily identified and operated under all operating conditions by a single action of either pilot with the hand that is normally used to actuate the power levels; and meets the requirements of § 25.777 (a),(b), and (c).

(ii) Provide a means for the flightcrew to deactivate the automatic CPR function. This means must be designed to prevent inadvertent deactivation.

(iii) Provide a means for the flightcrew to verify that the CFR system is in a condition to operate.

(e) Powerplant Instruments. In addition to the requirements of § 25.1305, a means must be provided to indicate when the CPR is in the armed or ready condition.

Issued in Renton, Washington, on March 6, 1997.

Neil D. Schalekamp,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service, ANM–100.

[FR Doc. 97–6528 Filed 3–13–97; 8:45 am]

BILLING CODE 4910–13–M

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14 CFR Part 39

[Docket No. 97–NM–28–AD]

RIN 2120–AA64

Airworthiness Directives; Boeing Model 737–100, –200, –300, –400, and –500 Series Airplanes

AGENCY: Federal Aviation Administration, DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: This document proposes the adoption of a new airworthiness directive (AD) that is applicable to all Boeing Model 737–100, –200, –300, –400, and –500 series airplanes. This proposal would require installation of a newly designed rudder-limiting device and yaw damper system. This proposal is prompted by a report indicating that a full rudder input, either commanded or uncommanded, could result in a rapid roll upset; and by reports of malfunctions of the yaw damper system. The actions specified by the proposed AD are intended to prevent excessive rudder authority and consequent reduced controllability of the airplane; and malfunctions of the yaw damper system, which could result in sudden uncommanded yawing of the airplane and consequent injury to passengers and crewmembers.

DATES: Comments must be received by April 23, 1997.

ADDRESSES: Submit comments in triplicate to the Federal Aviation Administration (FAA), Transport Airplane Directorate, ANM–103, Attention: Rules Docket No. 97–NM–28–AD, 1601 Lind Avenue, SW., Renton, Washington 98055–4056. Comments may be inspected at this location between 9:00 a.m. and 3:00 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: T. Tin Truong, Aerospace Engineer, Systems and Equipment Branch, ANM–130S, FAA, Transport Airplane Directorate, Seattle Aircraft Certification Office, 1601 Lind Avenue, SW., Renton, Washington 98055–4056; telephone (206) 227–2552; fax (206) 227–1181.

SUPPLEMENTARY INFORMATION:

Comments Invited

Interested persons are invited to participate in the making of the proposed rule by submitting such written data, views, or arguments as they may desire. Communications shall identify the Rules Docket number and be submitted in triplicate to the address specified above. All communications received on or before the closing date for comments, specified above, will be considered before taking action on the proposed rule. The proposals contained in this notice may be changed in light of the comments received.

Comments are specifically invited on the overall regulatory, economic, environmental, and energy aspects of the proposed rule. All comments submitted will be available, both before and after the closing date for comments, in the Rules Docket for examination by interested persons. A report summarizing each FAA-public contact concerned with the substance of this proposal will be filed in the Rules Docket.

Commenters wishing the FAA to acknowledge receipt of their comments submitted in response to this notice must submit a self-addressed, stamped postcard on which the following statement is made: ''Comments to Docket Number 97–NM–28–AD.'' The postcard will be date stamped and returned to the commenter.

Availability of NPRMs

Any person may obtain a copy of this NPRM by submitting a request to the FAA, Transport Airplane Directorate, ANM–103, Attention: Rules Docket No. 97–NM–28–AD, 1601 Lind Avenue, SW., Renton, Washington 98055–4056.

Discussion

In September 1994, an accident involving a Boeing Model 737–300 series airplane occurred near Pittsburgh, Pennsylvania. The National Transportation Safety Board (NTSB) has not yet determined the cause of that accident. However, the FAA has received a report indicating that piloted computer simulations of the accident revealed that a full rudder input, either commanded or uncommanded, could result in a rapid roll upset similar to the aircraft responses recorded on the flight data recorder of the accident airplane. Investigation revealed that, during certain combinations of flap settings and airspeeds, the amount of rudder deflection available is greater than needed for control of the airplane. A full rudder deflection (hardover) with such excessive rudder authority can result in a rolling moment due to sideslip that exceeds the maximum rolling moment available by control wheel inputs. This condition, if not corrected, could result in reduced controllability of the airplane unless the flight crew takes prompt and appropriate action. [In this regard, the FAA issued AD 96–26–07, amendment 39–9871 (62 FR 15, January 2, 1997) to amend the Airplane Flight Manual to provide the flight crew with the proper control techniques in the event of such an occurrence.]

Additionally, the FAA has received a number of reports of malfunctions of the yaw damper system. These malfunctions may have been caused by failure of the rate gyroscope of the yaw damper coupler as a result of wear of the rotor bearing, and contamination and shorting of the electrical connectors or surface position sensors in the area of the yaw damper servo-actuator. Such malfunctions of the yaw damper system, if not corrected, could result in sudden uncommanded yawing of the airplane and consequent injury to passengers and crewmembers.

Boeing has advised the FAA that it has designed a rudder-limiting device and a new yaw damper for installation on the latest versions of Model 737 series airplanes currently undergoing certification. Both of these systems are capable of being installed on the existing fleet of Model 737 series airplanes. Boeing has not yet released a service bulletin reflecting these changes.

FAA's Determinations

In light of this information, the FAA finds that installation of a newly designed rudder-limiting device and yaw damper system are required to ensure the safety of the affected fleet. Installation of a rudder-limiting device is necessary to reduce the rudder authority at altitudes above 1,500 feet above ground level (AGL) so that, if any inadvertent hardover occurs, the resultant roll upset can be controlled with control wheel inputs. Installation of a new yaw damper system is necessary to improve the reliability of the system and its fault monitoring capability, which will prevent uncommanded yawing of the airplane.

Explanation of Requirements of Proposed Rule

Since an unsafe condition has been identified that is likely to exist or develop on other products of this same type design, the proposed AD would require installation of a newly designed rudder-limiting device and yaw damper system. The actions would be required to be accomplished in accordance with a method approved by the FAA.

Cost Impact

There are approximately 2,900 Model 737 series airplanes of the affected design in the worldwide fleet. The FAA estimates that 1,350 airplanes of U.S. registry would be affected by this proposed AD.

The FAA estimates that it would take approximately 87 work hours per airplane to accomplish the proposed installation of a newly designed rudder-limiting device, and that the average labor rate is $60 per work hour. Required parts would be supplied by the manufacturer at no cost to operators. Based on these figures, the cost impact of the proposed AD on U.S. operators is estimated to be $7,047,000, or $5,220 per airplane.

The FAA also estimates that it would take approximately 20 work hours per airplane to accomplish the proposed installation of a newly designed yaw damper system, and that the average labor rate is $60 per work hour. Required parts would be supplied by the manufacturer at no cost to operators. Based on these figures, the cost impact of the proposed AD on U.S. operators is estimated to be $1,620,000, or $1,200 per airplane.

The cost impact figures discussed above are based on assumptions that no operator has yet accomplished any of the proposed requirements of this AD action, and that no operator would accomplish those actions in the future if this AD were not adopted.

The FAA recognizes that the obligation to maintain aircraft in an airworthy condition is vital, but sometimes expensive. Because AD's require specific actions to address specific unsafe conditions, they appear to impose costs that would not otherwise be borne by operators. However, because of the general obligation of operators to maintain aircraft in an airworthy condition, this appearance is deceptive. Attributing those costs solely to the issuance of this AD is unrealistic because, in the interest of maintaining safe aircraft, prudent operators would accomplish the required actions even if they were not required to do so by the AD.

A full cost-benefit analysis has not been accomplished for this proposed AD. As a matter of law, in order to be airworthy, an aircraft must conform to its type design and be in a condition for safe operation. The type design is approved only after the FAA makes a determination that it complies with all applicable airworthiness requirements. In adopting and maintaining those requirements, the FAA has already made the determination that they establish a level of safety that is cost-beneficial. When the FAA, as in this proposed AD, makes a finding of an unsafe condition, this means that the original cost-beneficial level of safety is no longer being achieved and that the proposed actions are necessary to restore that level of safety. Because this level of safety has already been determined to be cost-beneficial, a full cost-benefit analysis for this proposed AD would be redundant and unnecessary.

Regulatory Impact

The regulations proposed herein would not have substantial direct effects 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. Therefore, in accordance with Executive Order 12612, it is determined that this proposal would not have sufficient federalism implications to warrant the preparation of a Federalism Assessment.

For the reasons discussed above, I certify that 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) if promulgated, 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. A copy of the draft regulatory evaluation prepared for this action is contained in the Rules Docket. A copy of it may be obtained by contacting the Rules Docket at the location provided under the caption **ADDRESSES.**

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Safety.

The Proposed Amendment

Accordingly, pursuant to the authority delegated to me by the Administrator, the Federal Aviation Administration proposes to amend 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. Section 39.13 is amended by adding the following new airworthiness directive:

Boeing: Docket 97–NM–28–AD.

Applicability: All Model 737–100, –200, –300, –400, and –500 series airplanes, certificated in any category.

Note 2: 1: This AD applies to each airplane identified in the preceding applicability provision, regardless of whether it has been otherwise modified, altered, or repaired in the area subject to the requirements of this AD. For airplanes that have been modified, altered, or repaired so that the performance of the requirements of this AD is affected, the owner/operator must request approval for an alternative method of compliance in accordance with paragraph (b) of this AD. The request should include an assessment of the effect of the modification, alteration, or repair on the unsafe condition addressed by this AD; and, if the unsafe condition has not been eliminated, the request should include specific proposed actions to address it.

Compliance: Required as indicated, unless accomplished previously.

To prevent excessive rudder authority and consequent reduced controllability of the airplane; and malfunctions of the yaw damper system, which could result in sudden uncommanded yawing of the airplane and consequent injury to passengers and crewmembers; accomplish the following:

(a) Within 3 years after the effective date of this AD, accomplish paragraphs (a)(1) and (a)(2) of this AD in accordance with a method approved by the Manager, Seattle Aircraft Certification Office (ACO), FAA, Transport Airplane Directorate.

(1) Install a newly designed rudder-limiting device that reduces the rudder authority at altitudes above 1,500 feet above ground level (AGL).

(2) Install a newly designed yaw damper system that improves the reliability and fault monitoring capability.

(b) An alternative method of compliance or adjustment of the compliance time that provides an acceptable level of safety may be used if approved by the Manager, Seattle ACO. Operators shall submit their requests through an appropriate FAA Principal Maintenance Inspector, who may add comments and then send it to the Manager, Seattle ACO.

Note 2: Information concerning the existence of approved alternative methods of compliance with this AD, if any, may be obtained from the Seattle ACO.

(c) Special flight permits may be issued in accordance with sections 21.197 and 21.199 of the Federal Aviation Regulations (14 CFR 21.197 and 21.199) to operate the airplane to a location where the requirements of this AD can be accomplished.

Issued in Renton, Washington, on March 7, 1997.

Ronald T. Wojnar,

Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 97–6436 Filed 3–13–97; 8:45 am]

BILLING CODE 4910–13–P

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14 CFR Part 39

[Docket No. 96–NM–152–AD]

RIN 2120–AA64

Airworthiness Directives; Boeing Model 737–100 and –200 Series Airplanes

AGENCY: Federal Aviation Administration, DOT.

ACTION: Supplemental notice of proposed rulemaking; reopening of comment period.

SUMMARY: This document revises an earlier proposed airworthiness directive (AD), applicable to all Boeing Model 737–100 and –200 series airplanes, that would have required replacement of certain outboard and inboard wheel halves with improved wheel halves. That action also would have required cleaning and inspecting certain outboard and inboard wheel halves for corrosion, missing paint in large areas, and cracks; and repair or replacement of the wheel halves with serviceable wheel halves, if necessary. That proposal was prompted by a review of the design of the flight control systems on Model 737 series airplanes. This action revises the proposed rule by extending the compliance time, revising the applicability of the AD, and clarifying part and serial numbers of affected wheel assemblies and halves. The actions specified by this proposed AD are intended to prevent failure of the wheel flanges, which could result in damage to the hydraulics systems, jammed flight controls, loss of electrical power, or other combinations of failures; and consequent reduced controllability of the airplane.

DATES: Comments must be received by April 3, 1997.

ADDRESSES: Submit comments in triplicate to the Federal Aviation Administration (FAA), Transport Airplane Directorate, ANM–103, Attention: Rules Docket No. 96–NM–152–AD, 1601 Lind Avenue, SW., Renton, Washington 98055–4056. Comments may be inspected at this location between 9:00 a.m. and 3:00 p.m., Monday through Friday, except Federal holidays.

The service information referenced in the proposed rule may be obtained from Allied Signal Aerospace Company, Bendix Wheels and Brakes Division, South Bend, Indiana 46624; and Bendix, Aircraft Brake and Strut Division, 3520 West Mestmoor Street, South Bend, Indiana 46624. This information may be examined at the FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington.

FOR FURTHER INFORMATION CONTACT: David Herron, Aerospace Engineer, Systems and Equipment Branch, ANM–130S, FAA, Seattle Aircraft Certification Office, 1601 Lind Avenue, SW., Renton, Washington; telephone (206) 227–2672; fax (206) 227–1181.

SUPPLEMENTARY INFORMATION:

Comments Invited

Interested persons are invited to participate in the making of the proposed rule by submitting such written data, views, or arguments as they may desire. Communications shall identify the Rules Docket number and be submitted in triplicate to the address specified above. All communications received on or before the closing date for comments, specified above, will be considered before taking action on the proposed rule.

The proposals contained in this notice may be changed in light of the comments received.

Comments are specifically invited on the overall regulatory, economic, environmental, and energy aspects of the proposed rule. All comments submitted will be available, both before and after the closing date for comments, in the Rules Docket for examination by interested persons. A report summarizing each FAA-public contact concerned with the substance of this proposal will be filed in the Rules Docket.

Commenters wishing the FAA to acknowledge receipt of their comments submitted in response to this notice must submit a self-addressed, stamped postcard on which the following statement is made: ‘‘Comments to Docket Number 96–NM–152–AD.’’ The postcard will be date stamped and returned to the commenter.

Availability of NPRMs

Any person may obtain a copy of this NPRM by submitting a request to the FAA, Transport Airplane Directorate, ANM–103, Attention: Rules Docket No. 96–NM–152–AD, 1601 Lind Avenue, SW., Renton, Washington 98055–4056.

Discussion

A proposal to amend part 39 of the Federal Aviation Regulations (14 CFR part 39) to add an airworthiness directive (AD), applicable to all Boeing Model 737–100 and –200 series airplanes, was published as a notice of proposed rulemaking (NPRM) in the Federal Register on August 28, 1996 (61 FR 44245). That NPRM would have required replacement of certain outboard and inboard wheel halves with improved wheel halves. That NPRM also would have required cleaning and inspecting certain outboard and inboard wheel halves for corrosion, missing paint in large areas, and cracks; and repair or replacement of the wheel halves with serviceable wheel halves, if necessary. That NPRM was prompted by a review of the design of the flight control systems on Model 737 series airplanes. The actions specified by that NPRM are intended to prevent damage to the wheel flanges, which could result in failure of the hydraulics systems, jammed flight controls, loss of electrical power, or other combinations of failures; and consequent reduced controllability of the airplane.

Actions Since Issuance of Previous Proposal

Due consideration has been given to the comments received in response to the NPRM.

Support for the Proposal

Two commenters support the proposed rule.

Requests to Reopen Comment Period

Several commenters request that the proposal be reissued and the public comment period reopened. The commenters ask that the intent of the proposal be clarified. The commenters state that the proposal appears to require that an inspection and a replacement be accomplished concurrently within 180 days. Allied Signal indicates that it is unclear why operators should be required to replace wheel halves and then inspect those wheel halves that were just removed.

In its justification for the request to reopen the comment period, another commenter states that the issue addressed in the proposed AD arises from a failure that occurred on a military aircraft. The commenter indicates that, when maintained properly and operated on civilian airliners, certain wheel halves are not subject to the questionable maintenance practices and adverse operational conditions often associated with military hardware. The commenter adds that, in particular, the inspections required at tire replacement occur far more frequently due to utilization differences. The commenter believes that strengthened inspection requirements in accordance with the latest manufacturer's recommendations can provide for safe operation of the older wheels until replacements would normally be available.

The FAA concurs with the commenters' requests to reopen the comment period for this proposed rule and to provide clarification of the intent of the proposal. The intent of this proposed AD is that the affected fleet be equipped eventually with more resilient wheel halves that provide greater tolerance for corrosion and handling damage. Some failures of wheel halves have occurred because indications of corrosion or handling damage were not detected in a timely manner. Therefore, the FAA included a requirement in the original NPRM indicating that, until the time that the existing wheel halves can be replaced with the more resilient wheel halves, repetitive cleaning and inspections of the wheel halves must be performed in accordance with the cleaning/inspection method described in Allied Signal Service Bulletin No. 737–32–026. Accomplishment of these repetitive actions will ensure that an acceptable level of safety is maintained until the wheel halves are replaced.

The FAA has revised this supplemental NPRM to clarify these issues:

- The repetitive inspection requirement, which appeared as paragraph (b) of the original NPRM, is contained in paragraph (a) of this supplemental NPRM. Paragraph (a) of this supplemental NPRM has been revised to clarify that the inspections of the wheel halves must be repeated until the wheel halves are replaced.
- The replacement requirement, which appeared in paragraph (a) of the original NPRM, is contained in paragraph (b) of this supplemental NPRM. Paragraph (b) of this supplemental NPRM has been revised to clarify that accomplishment of the replacement terminates the repetitive inspections required by paragraph (a).

Request for Extended Compliance Time

Three commenters express concern that replacement of certain outboard and inboard wheel halves with improved halves cannot be supported within the proposed compliance time of 180 days. One of these commenters, Allied Signal, suggests that the compliance time be extended to 365 days, and that paragraph (c) of the original NPRM be deleted. Allied Signal indicates that the lead time necessary to order and receive forgings, machine, finish, and ship replacement wheels involves approximately 120 days, which is a significant portion of the proposed 180-day compliance time. Allied Signal states that it does not have sufficient information to determine how many wheels need replacement, and may not have this information until a final rule is effective and orders for replacements arrive.

In light of these requests, the FAA has reconsidered the compliance times proposed in the original NPRM. The FAA considers that the compliance time of 180 days (and thereafter at each tire change) for inspections of the wheel halves, as proposed in paragraph (b) of the original NPRM, is appropriate. The FAA considers that these repetitive inspections must be accomplished at the originally proposed intervals in order to provide an acceptable level of safety until the replacement can be accomplished.

However, in consideration of parts availability, the FAA has determined that the compliance time for replacement of the wheel halves can be extended from 180 days to two years without compromising safety, and that paragraph (c) of the original NPRM can be removed from this supplemental NPRM. Given this revised compliance time for accomplishment of the replacement, the FAA estimates that approximately four tire changes would be accomplished in the two-year period prior to the time the replacement would be required. The compliance time specified in paragraph (b) of this supplemental NPRM has been revised accordingly. In addition, paragraph (c) of the original NPRM has been removed from this supplemental NPRM.

Requests for Clarification of Part Numbering System

Two commenters request clarification of the part numbering system specified in the proposal. Further, Allied Signal recommends that serial number H–1049 be used in all places where serial number H–999 appeared in the NPRM to avoid numerical discrepancies and to ensure adequate coverage of these wheel halves. Allied Signal submits two sets of suggested changes to the NPRM: one set based on an intent to remove all affected wheels from service, and the other set based on an intent to inspect all affected wheels and remove from service only those with cracks.

Allied Signal states that a misunderstanding exists with regard to the serial numbering system used by Aircraft Landing Systems (formerly Bendix). Allied Signal clarifies that wheels having a ''B'' prefix serial number are original equipment wheels shipped from the factory. Individual inboard and individual outboard wheel halves are given the same ''B'' serial number on the final production line and mated together to form a complete wheel assembly. Wheel halves having serial numbers with an ''H'' prefix are replacement service halves. Availability of a service wheel half allows an operator to replace a damaged wheel half instead of the entire wheel assembly. Individual inboard and outboard service halves are not mated together to form a complete assembly; they are shipped independently of each other.

Allied Signal also clarifies that Bendix Service Information Letter (SIL) 392, Revision 1, dated November 15, 1979, and Allied Signal Service Bulletin No. 737–32–026, dated April 26, 1988, apply to both the ''H'' and ''B'' prefix serial numbers, not just the ''H'' prefix serial numbers used in the ''B'' prefix wheel assemblies.

The FAA agrees that clarification of the part and serial numbers specified in the original NPRM is necessary. As stated previously, the FAA intends that all affected wheels be removed from service; the FAA concurs with the changes suggested by Allied Signal based on that intent. Paragraphs (a) and (b) of this supplemental NPRM reflect the appropriate part and serial numbers provided by Allied Signal. In addition, serial number H–1049 has been specified in this supplemental NPRM in place of serial number H–999.

Request to Revise the Applicability of the Proposed AD

The Air Transport Association (ATA) of America, on behalf of one of its members, requests that the applicability of the proposed AD be limited only to the Bendix main wheel assemblies that prompted the airworthiness concern. The ATA states that the proposed applicability affects even operators with BFGoodrich brakes. The commenter concludes that, unless operators of airplanes equipped with BFGoodrich brakes submit a request for and receive approval of an alternative method of compliance (AMOC), those operators are considered in noncompliance with the AD.

The FAA concurs with the commenter's request to revise the applicability of the original NPRM. This FAA has revised the applicability of this supplemental NPRM to specify that the proposed rule applies only to Boeing Model 737–100 and –200 series airplanes equipped with Bendix main wheel assemblies having part number 2601571–1. Paragraphs (a) and (b) of the supplemental NPRM specify the serial numbers of the inboard and outboard wheel halves that are affected.

The FAA also clarifies that operators of airplanes equipped with BFGoodrich brakes would not be required to submit a request for approval of an AMOC. Although the applicability of the original NPRM identified the affected airplanes as ''all Model 737–100 and –200 series airplanes,'' paragraphs (a) and (b) specified clearly that only those airplanes equipped with Bendix main wheel assemblies having certain part and serial numbers are affected by the proposed rule. Therefore, operators of airplanes equipped with other main wheel assemblies are not subject to the requirements of this AD, and would have no reason to apply for approval of an AMOC.

Request to Revise Statement of Findings of Critical Design Review Team

One commenter requests the second paragraph of the Discussion section that appeared in the preamble to the proposed rule be revised to accurately reflect the findings of the Critical Design Review (CDR) team. The commenter asks that the FAA delete the one sentence in that paragraph, which read: ''The recommendations of the team include various changes to the design of the flight control systems of these airplanes, as well as correction of certain design deficiencies.'' The commenter suggests that the following sentences should be added: ''The team did not find any design issues that could lead to a definite cause of the accidents that gave rise to this effort. The recommendations of the team include various changes to the design of the flight control systems of these airplanes, as well as incorporation of certain design improvements in order to enhance its already acceptable level of safety.''

The FAA acknowledges that the CDR team did not find any design issue that could lead to a definite cause of the accidents that gave rise to this effort. However, as a result of having conducted the CDR of the flight control systems on Boeing Model 737 series airplanes, the team indicated that there are a number of recommendations that should be addressed by the FAA for each of the various models of the Model 737. In reviewing these recommendations, the FAA has concluded that they address unsafe conditions that must be corrected through the issuance of AD's. Therefore, the FAA does not concur that these design changes merely ''enhance [the Model 737's] already acceptable level of safety.''

Conclusion

Since these changes provide significant clarification of the intent and requirements of the originally proposed rule, the FAA has determined that it is in the public interest to reopen the comment period to provide additional opportunity for public comment.

Cost Impact

There are approximately 634 Boeing Model 737–100 and –200 series airplanes of the affected design in the worldwide fleet. The FAA estimates that 241 airplanes of U.S. registry would be affected by this proposed AD.

The FAA estimates that it would take approximately 4 work hours per airplane to accomplish the proposed replacement of wheel halves, and that the average labor rate is $60 per work hour. Required parts would cost approximately $20,212 per airplane. Based on these figures, the cost impact of the proposed replacement on U.S. operators is estimated to be $4,928,932, or $20,452 per airplane.

The FAA also estimates that it would take approximately 2 work hours per airplane to accomplish the proposed cleaning and inspection, and that the average labor rate is $60 per work hour. Based on these figures, the cost impact of the proposed cleaning and inspection on U.S. operators is estimated to be $28,920, or $120 per airplane.

The cost impact figures discussed above are based on assumptions that no operator has yet accomplished any of the proposed requirements of this AD action, and that no operator would accomplish those actions in the future if this AD were not adopted.

Regulatory Impact

The regulations proposed herein would not have substantial direct effects 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. Therefore, in accordance with Executive Order 12612, it is determined that this proposal would not have sufficient federalism implications to warrant the preparation of a Federalism Assessment.

For the reasons discussed above, I certify that 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) if promulgated, 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. A copy of the draft regulatory evaluation prepared for this action is contained in the Rules Docket. A copy of it may be obtained by contacting the Rules Docket at the location provided under the caption **ADDRESSES.**

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Safety.

The Proposed Amendment

Accordingly, pursuant to the authority delegated to me by the Administrator, the Federal Aviation Administration proposes to amend 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. Section 39.13 is amended by adding the following new airworthiness directive:

BOEING: Docket 96-NM–152-AD.

Applicability: Boeing Model 737–100 and -200 series airplanes equipped with Bendix main wheel assemblies having part number 2601571–1, certificated in any category.

Note 1: This AD applies to each airplane identified in the preceding applicability provision, regardless of whether it has been otherwise modified, altered, or repaired in the area subject to the requirements of this AD. For airplanes that have been modified, altered, or repaired so that the performance of the requirements of this AD is affected, the owner/operator must request approval for an alternative method of compliance in accordance with paragraph (c) of this AD. The request should include an assessment of the effect of the modification, alteration, or repair on the unsafe condition addressed by this AD; and, if the unsafe condition has not been eliminated, the request should include specific proposed actions to address it.

Compliance: Required as indicated, unless accomplished previously.

To prevent failure of the wheel flanges, which could result in damage to the hydraulics systems, jammed flight controls, loss of electrical power, or other combinations of failures; and consequent reduced controllability of the airplane, accomplish the following:

(a) For airplanes equipped with a Bendix main wheel assembly having part number (P/N) 2601571–1 with an inboard wheel half with serial number (S/N) B–5999 or lower, or S/N H–1799 or lower; or with an outboard wheel half with S/N B–5999 or lower, or S/N H–1049 or lower; accomplish the following:

(1) Within 180 days after the effective date of this AD, and thereafter at each tire change until the replacement required by paragraph (b) of this AD is accomplished:

Accomplish the actions specified in paragraphs (a)(1)(i), (a)(1)(ii), and (a)(1)(iii) of this AD, in accordance with the Accomplishment Instructions of Allied Signal Service Bulletin No. 737–32–026, dated April 26, 1988, including Attachments 1 and 2.

(i) Clean any inboard and outboard wheel half specified in paragraph (a) of this AD. And

(ii) Inspect the wheel halves for corrosion or missing paint. If any corrosion is found, or if any paint is missing in large areas, prior to further flight, strip or remove paint, and remove any corrosion. And

(iii) Perform an eddy current inspection to detect cracks of the bead seat area.

(2) If any cracking is found during the inspections required by this paragraph, prior to further flight, repair or replace the wheel halves with serviceable wheel halves in accordance with procedures specified in the Component Maintenance Manual.

(b) For airplanes equipped with a Bendix main wheel assembly having P/N 2601571–1 with an inboard wheel half with S/N B–5999 or lower, or S/N H–1799 or lower; or with an outboard wheel half with S/N B–5999 or lower, or S/N H–1049 or lower; accomplish the following: Within 2 years after the effective date of this AD, accomplish the actions specified in paragraphs (b)(1) and (b)(2) of this AD, in accordance with Bendix Service Information Letter (SIL) 392, Revision 1, dated November 15, 1979. Accomplishment of the replacement constitutes terminating action for the repetitive inspections required by paragraph (a) of this AD.

(1) Remove any inboard wheel half specified in paragraph (b) of this AD, and replace it with an inboard wheel half having P/N 2607046, S/N B–6000 or greater, or S/N H–1800 or greater. And

(2) Remove any outboard wheel half specified in paragraph (b) of this AD, and replace it with an outboard wheel half having P/N 2607047, S/N B–6000 or greater, or S/N H–1050 or greater.

(c) An alternative method of compliance or adjustment of the compliance time that provides an acceptable level of safety may be used if approved by the Manager, Seattle Aircraft Certification Office (ACO), FAA, Transport Airplane Directorate. Operators shall submit their requests through an appropriate FAA Principal Maintenance Inspector, who may add comments and then send it to the Manager, Seattle ACO.

Note 2: Information concerning the existence of approved alternative methods of compliance with this AD, if any, may be obtained from the Seattle ACO.

(d) Special flight permits may be issued in accordance with sections 21.197 and 21.199 of the Federal Aviation Regulations (14 CFR 21.197 and 21.199) to operate the airplane to a location where the requirements of this AD can be accomplished. Issued in Renton, Washington, on March 7, 1997.

Darrell M. Pederson,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 97–6438 Filed 3–13–97; 8:45 am]

BILLING CODE 4910–13–U

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14 CFR Part 39

[Docket No. 97–NM–29–AD]

RIN 2120–AA64

Airworthiness Directives; Boeing Model 737–100, –200, –300, –400, and –500 Series Airplanes

AGENCY: Federal Aviation Administration, DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: This document proposes the supersedure of two existing airworthiness directives (AD), applicable to certain Boeing Model 737 series airplanes, that currently require tests of the main rudder power control unit (PCU) to detect excessive internal leakage of hydraulic fluid, stalling, or reversal, and to verify proper operation of the PCU; and replacement of the PCU with a unit having a different part number, if necessary. This action would add requirements for replacement of the PCU and the vernier control rod bolt with newly designed units. This action also would add a requirement for leak tests of the PCU, and replacement of the PCU with a serviceable or newly designed unit, if necessary. This proposal is prompted by reports of fracturing of the vernier control rod bolts as a result of the shank of the bolt running into the threads on the nutplate during installation of the rod. The actions specified by the proposed AD are intended to prevent such fracturing, which could result in uncommanded movements of the rudder, and consequent reduced controllability of the airplane.

DATES: Comments must be received by April 23, 1997.

ADDRESSES: Submit comments in triplicate to the Federal Aviation Administration (FAA), Transport Airplane Directorate, ANM–103, Attention: Rules Docket No. 97–NM–29–AD, 1601 Lind Avenue, SW., Renton, Washington 98055–4056. Comments may be inspected at this location between 9:00 a.m. and 3:00 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT:
Kenneth W. Frey, Aerospace Engineer, Systems and Equipment Branch, ANM–130S, FAA, Transport Airplane Directorate, Seattle Aircraft Certification Office, 1601 Lind Avenue, SW., Renton, Washington 98055–4056; telephone (206) 227–2673; fax (206) 227–1181.

SUPPLEMENTARY INFORMATION:

Comments Invited

Interested persons are invited to participate in the making of the proposed rule by submitting such written data, views, or arguments as they may desire. Communications shall identify the Rules Docket number and be submitted in triplicate to the address specified above. All communications received on or before the closing date for comments, specified above, will be considered before taking action on the proposed rule. The proposals contained in this notice may be changed in light of the comments received.

Comments are specifically invited on the overall regulatory, economic, environmental, and energy aspects of the proposed rule. All comments submitted will be available, both before and after the closing date for comments, in the Rules Docket for examination by interested persons. A report summarizing each FAA-public contact concerned with the substance of this proposal will be filed in the Rules Docket.

Commenters wishing the FAA to acknowledge receipt of their comments submitted in response to this notice must submit a self-addressed, stamped postcard on which the following statement is made: ''Comments to Docket Number 97–NM–29–AD.'' The postcard will be date stamped and returned to the commenter.

Availability of NPRMs

Any person may obtain a copy of this NPRM by submitting a request to the FAA, Transport Airplane Directorate, ANM–103, Attention: Rules Docket No. 97–NM–29–AD, 1601 Lind Avenue, SW., Renton, Washington 98055–4056.

Discussion

On January 3, 1994, the FAA issued AD 94–01–07, amendment 39–8789 (59 FR 4570, February 1, 1994), applicable to certain Boeing Model 737 series airplanes, to require repetitive periodic tests of the main rudder power control unit (PCU) to detect excessive internal leakage of hydraulic fluid, stalling, or reversal, and the eventual replacement of the PCU with an improved model. That action was prompted by results of an investigation, which revealed that there was a remote possibility that the secondary slide in the servo valve of certain PCU's could go past the intended maximum-travel position. The requirements of that AD are intended to prevent secondary slide overtravel from occurring, which could cause the rudder actuator piston and the rudder to operate with reduced force capability or to move in a direction opposite to the intended direction; this could result in reduced controllability of the airplane.

On November 7, 1996, the FAA issued AD 96–23–51, amendment 39–9818 (61 FR 59317, November 22, 1996), applicable to all Boeing Model 737 series airplanes, to require repetitive periodic tests to verify proper operation of the main rudder PCU, and replacement of the PCU with a new unit, if necessary. That action was prompted by tests of the PCU conducted by the manufacturer, which demonstrated another very remote potential failure scenario that was previously unknown. The requirements of that AD are intended to prevent rudder motion in the opposite direction of the rudder command.

Actions Since Issuance of Previous Rules

In the preamble to AD 96–23–51, the FAA indicated that it considered that AD to be interim action, and that further rulemaking action would be considered once final action was identified. Since the issuance of that AD, Boeing has advised the FAA that it is designing new main rudder PCU's and a new bolt for the vernier control rod for installation on the latest versions of Model 737 series airplanes currently undergoing certification. These new PCU's and bolts are capable of being installed on the existing fleet of Model 737 series airplanes. At this time, the testing and design analyses necessary for FAA approval have not yet been completed; therefore, Boeing has not yet released a service bulletin reflecting these changes. The FAA anticipates that these tests and analyses will be completed and the service bulletin approved prior to issuance of a final rule.

In addition, the FAA also received reports indicating that the outer bolts for the vernier control rod fractured in two cases. Fracturing of the outer bolt was caused by the shank of the bolt running into the threads on the nutplate during installation of the vernier control rod. These bolts have a dual load path. If the second load path of the bolt fractures, the manual input link to the main rudder PCU would be disconnected. Such fracturing, if not corrected, could result in uncommanded movements of the rudder, and consequent reduced controllability of the airplane.

FAA's Determinations

In light of this information, the FAA has determined the following:

1. The main rudder PCU's must be replaced with newly designed units. These new PCU's will have a valve that is similar to the valve installed on the existing units in that the valve is dual-concentric in design; however, the new units will have different characteristics for the flow of hydraulic fluid. Installation of the new units will eliminate the possibility of improper flow of hydraulic fluid. Replacement of the existing units with new units constitutes terminating action for the actions required by those existing AD's.

2. The bolt for the vernier control rod must be replaced with a newly designed bolt. Installation of the new bolt will eliminate the possibility of the shank of the bolt running into the threads on the nutplate.

3. Although the FAA has received no reports indicating that an in-flight engine out or loss of hinge moment has resulted in reduced controllability of an airplane, high internal leakage in the main rudder PCU can exist. This high internal leakage could be caused by a jam in the slides of the servo valve or by other failures or wear within the PCU. Such leakage could result in reduced hinge moment capability of the rudder PCU, which could result in reduced controllability of the airplane at any time large rudder inputs are required (such as failure of the engine during takeoff). In light of this, the FAA finds that periodic inspections must be performed to detect high internal leakage of the main rudder PCU in a timely manner.

Explanation of Requirements of Proposed Rule

Since an unsafe condition has been identified that is likely to exist or develop on other products of this same type design, this proposed AD would supersede AD 94–01–07 and AD 96–23–51. The following requirements from the superseded AD's have been carried over into the proposed AD:

—Tests of the main rudder PCU to detect excessive internal leakage of hydraulic fluid, stalling, or reversal, and to verify proper operation of the PCU; and

—Replacement of the PCU with a unit having a different part number, if necessary.

It should be noted that paragraph (b) of AD 94–01–07 requires replacement of the PCU with a unit having part number

65–44861–11 or 65C37052–2, –3, –4, –5, –6, –7, –8, or –9. However, paragraph (b) of this proposed AD would allow for this replacement as an optional terminating action (instead of a required action) for the tests required by paragraph (a) of AD 94–01–07.

The proposed AD would add requirements for replacement of the PCU and vernier control rod bolt with newly designed units. Additionally, the proposed AD would add a requirement for repetitive leak tests of the PCU, and replacement of the PCU with a serviceable or newly designed unit, if necessary. These new actions would be required to be accomplished in accordance with a method approved by the FAA.

In developing an appropriate compliance time for the new requirements of this proposed AD, the FAA considered the safety implications, the time necessary for design and production of the new PCU's and bolts, and normal maintenance schedules for timely accomplishment of the proposed actions. In light of these items, the FAA has determined that a compliance time of two years for installation of the newly designed parts, and 6,000 flight hours for accomplishment of the repetitive leak tests, is appropriate.

Cost Impact

There are approximately 2,900 Model 737 series airplanes of the affected design in the worldwide fleet. The FAA estimates that 1,350 airplanes of U.S. registry would be affected by this proposed AD.

The tests that are currently required by AD 94–01–07 take approximately 8 work hours per airplane to accomplish, at an average labor rate of $60 per work hour. Based on these figures, the cost impact of the currently required tests on U.S. operators is estimated to be $648,000, or $480 per airplane, per test.

The replacement that is currently required by AD 94–01–07 takes approximately 20 work hours per airplane to accomplish, at an average labor rate of $60 per work hour. Required parts will be supplied by the manufacturer at no cost to operators. Based on these figures, the cost impact of the currently required replacement on U.S. operators is estimated to be $1,620,000, or $1,200 per airplane.

The tests that are currently required by AD 96–23–51 take approximately 2 work hours per airplane to accomplish, at an average labor rate of $60 per work hour. Based on these figures, the cost impact of the currently required tests on U.S. operators is estimated to be $162,000, or $120 per airplane, per test.

The replacement of the PCU that is proposed in this AD action would take approximately 9 work hours per airplane to accomplish, at an average labor rate of $60 per work hour. Required parts would be supplied by the manufacturer at no cost to operators. Based on these figures, the cost impact of the proposed replacement of the PCU on U.S. operators is estimated to be $729,000, or $540 per airplane.

The replacement of the vernier control rod bolt that is proposed in this AD action would take approximately 1 work hour per airplane to accomplish, at an average labor rate of $60 per work hour. Required parts would be supplied by the manufacturer at no cost to operators. Based on these figures, the cost impact of the proposed replacement of the vernier control rod bolt on U.S. operators is estimated to be $81,000, or $60 per airplane.

The leak tests that are proposed in this AD action would take approximately 8 work hours per airplane to accomplish, at an average labor rate of $60 per work hour. Based on these figures, the cost impact of the proposed requirements of this AD on U.S. operators is estimated to be $648,000, or $480 per airplane, per leak test.

The cost impact figures discussed above are based on assumptions that no operator has yet accomplished any of the current or proposed requirements of this AD action, and that no operator would accomplish those actions in the future if this AD were not adopted.

Regulatory Impact

The regulations proposed herein would not have substantial direct effects 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. Therefore, in accordance with Executive Order 12612, it is determined that this proposal would not have sufficient federalism implications to warrant the preparation of a Federalism Assessment.

For the reasons discussed above, I certify that 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) if promulgated, 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. A copy of the draft regulatory evaluation prepared for this action is contained in the Rules Docket. A copy of it may be obtained by contacting the Rules Docket at the location provided under the caption **ADDRESSES.**

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Safety.

The Proposed Amendment

Accordingly, pursuant to the authority delegated to me by the Administrator, the Federal Aviation Administration proposes to amend 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. Section 39.13 is amended by removing amendments 39–8789 (59 FR 4570, February 1, 1994) and 39–9818 (61 FR 59317, November 22, 1996), and by adding a new airworthiness directive (AD), to read as follows:

Boeing: Docket 97–NM–29–AD. Supersedes AD 94–01–07, Amendment 39–8789, and AD 96–23–51, Amendment 39–9818.

Applicability: All Model 737–100, –200, –300, –400, and –500 series airplanes, certificated in any category.

Note 1: This AD applies to each airplane identified in the preceding applicability provision, regardless of whether it has been otherwise modified, altered, or repaired in the area subject to the requirements of this AD. For airplanes that have been modified, altered, or repaired so that the performance of the requirements of this AD is affected, the owner/operator must request approval for an alternative method of compliance in accordance with paragraph (g) of this AD. The request should include an assessment of the effect of the modification, alteration, or repair on the unsafe condition addressed by this AD; and, if the unsafe condition has not been eliminated, the request should include specific proposed actions to address it.

Compliance: Required as indicated, unless accomplished previously.

To prevent uncommanded movements of the rudder, and consequent reduced controllability of the airplane, accomplish the following:

Restatement of Requirements of AD 94–01–07:

(a) Within 750 flight hours after March 3, 1994 (the effective date of AD 94–01–07, amendment 39–8789), perform a test of the main rudder PCU, part number 65–44861–2/–3/–4/–5/–6/–7/–8/–9, to detect internal leakage of hydraulic fluid, in accordance with Boeing Service Letter 737–SL–27–82–B, dated July 13, 1993.

(1) If no discrepancy, as described in paragraph 3.B. of the Service Letter, is

detected, repeat the test at intervals not to exceed 750 flight hours.

(2) If any discrepancy, as described in paragraph 3.B. of the Service Letter, is detected during any check, prior to further flight, accomplish either paragraph (a)(2)(i) or (a)(2)(ii) of this AD:

(i) Replace the main rudder PCU with a serviceable PCU in accordance with the Model 737 Overhaul Manual. After such replacement, repeat the test at intervals not to exceed 750 flight hours.

(ii) Replace the main rudder PCU with a new main rudder PCU having part number 65–44861–11 or 65C37052–2/–3/–4/–5/–6/–7/–8/–9, in accordance with Boeing Service Bulletin 737–27–1185, dated April 15, 1993. Such replacement constitutes terminating action for the tests required by paragraph (a) of this AD.

(b) Replacement of the main rudder PCU, part number 65–44861–( ), with a new main rudder PCU having part number 65–44861–11 or 65C37052–2/–3/–4/–5/–6/–7/–8/–9, in accordance with Boeing Service Bulletin 737–27–1185, dated April 15, 1993, constitutes terminating action for the tests required by paragraph (a) of this AD.

Restatement of Requirements of AD 96–23–51:

(c) Within 10 days after November 27, 1996 (the effective date of AD 96–23–51, amendment 39–9818), perform a test to verify proper operation of the rudder PCU, in accordance with Boeing Alert Service Bulletin 737–27A1202, dated November 1, 1996.

(1) If the rudder PCU operates properly, repeat the test thereafter at intervals not to exceed 250 flight hours.

(2) If the rudder PCU operates improperly, prior to further flight, replace the rudder PCU with a new rudder PCU, in accordance with the alert service bulletin. Repeat the test thereafter at intervals not to exceed 250 flight hours.

New Requirements of this AD:

(d) Within 2 years after the effective date of this AD, accomplish paragraphs (d)(1) and (d)(2) of this AD in accordance with a method approved by the Manager, Seattle Aircraft Certification Office (ACO), FAA, Transport Airplane Directorate. Accomplishment of these actions terminates the requirements of paragraphs (a), (b), and (c) of this AD.

(1) Replace any main rudder PCU having Boeing part number (P/N) 65–44861-( ) or P/N 65C37052-( ) with a new main rudder PCU that has been approved by the Manager, Seattle ACO.

(2) Replace the vernier control rod bolt having Boeing P/N 69–27229-( ) with a new bolt that has been approved by the Manager, Seattle ACO.

(e) Perform a leak test of the main rudder PCU in accordance with a method approved by the Manager, Seattle ACO, at the applicable times specified in paragraph (e)(1) or (e)(2) of this AD. If any discrepancy is found, prior to further flight, replace the PCU with a serviceable or newly designed unit in accordance with a method approved by the Manager, Seattle ACO.

Note 2: If the PCU is replaced in accordance with the requirements of paragraph (e) prior to accomplishing the replacement required by paragraph (d) of this AD, ''serviceable'' includes the newly designed PCU referenced in paragraph (d)(1) of this AD and PCU's having part number 65–44861–11 and 65C37052–2, -3, -4, -5, -6, -7, -8, and -9. However, after the PCU has been replaced in accordance with paragraph (d)(1) of this AD, ''serviceable'' is limited to the newly designed PCU's referenced in that paragraph.

(1) For airplanes on which the replacement specified in paragraph (a)(2)(ii), (b), or (c)(2) of this AD has been accomplished prior to the effective date of this AD: Within 4,000 flight hours after the effective date of this AD, and thereafter at intervals not to exceed 6,000 flight hours.

(2) For airplanes other than those identified in paragraph (e)(1) of this AD: Within 6,000 flight hours after accomplishment of the replacement required by paragraph (d)(1) of this AD, and thereafter at intervals not to exceed 6,000 flight hours.

(f) Once a newly designed PCU specified in paragraph (d)(1) of this AD is installed on an airplane, no operator shall install on that airplane any PCU other than a newly designed unit.

(g) An alternative method of compliance or adjustment of the compliance time that provides an acceptable level of safety may be used if approved by the Manager, Seattle ACO. Operators shall submit their requests through an appropriate FAA Principal Maintenance Inspector, who may add comments and then send it to the Manager, Seattle ACO.

Note 3: Information concerning the existence of approved alternative methods of compliance with this AD, if any, may be obtained from the Seattle ACO.

(h) Special flight permits may be issued in accordance with sections 21.197 and 21.199 of the Federal Aviation Regulations (14 CFR 21.197 and 21.199) to operate the airplane to a location where the requirements of this AD can be accomplished.

Issued in Renton, Washington, on March 7, 1997.

Ronald T. Wojnar,

Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 97–6437 Filed 3–13–97; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF THE TREASURY

Customs Service

19 CFR Part 146

RIN 1515–AC05

Weekly Entry Procedure for Foreign Trade Zones

AGENCY: U.S. Customs Service, Treasury.

ACTION: Proposed rule.

SUMMARY: This document proposes to amend and expand the weekly entry procedure for foreign trade zones under certain circumstances to include merchandise involved in activities other than exclusively assembly-line type production operations. Under the proposed expanded procedure, weekly entries covering the estimated removals of merchandise for the weekly period and the associated entry summaries would have to be filed exclusively through the Automated Broker Interface. The expanded weekly procedure, which, as is presently the case, would remain an entirely optional procedure, would thus be conducted in a fully paperless environment. The expanded weekly procedure would reduce the number of entries from zones as well as automate and expedite the processing of such entries. The proposed expansion of the weekly procedure would allow zone users to not have to delay their operations pending the acceptance of an entry and Customs examination of the subject merchandise. 2

DATES: Comments must be received on or before April 14, 1997.

ADDRESSES: Written comments (preferably in triplicate) may be addressed to the Regulations Branch, Office of Regulations and Rulings, U.S. Customs Service, 1301 Constitution Avenue, N.W., Washington, D.C. 20229. Comments may be inspected at the Regulations Branch, Office of Regulations and Rulings, Franklin Court, 1099 14th Street, N.W., Suite 4000, Washington, D.C.

FOR FURTHER INFORMATION CONTACT: Marsha Malbrough, Office of Field Operations, (202–927–0457).

SUPPLEMENTARY INFORMATION:

Background

The Foreign Trade Zones Act of 1934, as amended (19 U.S.C. 81a–u) (the ''FTZA''), provides for the establishment and regulation of foreign trade zones. Foreign trade zones are secured areas to which foreign and domestic merchandise, except that prohibited by law, may be brought for the purposes enumerated in the FTZA without being subject to the Customs laws of the U.S. Foreign trade zones, by virtue of being exempt from the Customs laws, are intended to attract and promote international trade and commerce. Part 146, Customs Regulations (19 CFR part 146), sets forth the documentation and recordkeeping requirements governing the admission of merchandise into a zone, 3 its removal from the zone, and, among other things, its manipulation, manufacture, storage, destruction or exhibition, while in the zone.

The current weekly entry procedure for foreign trade zones, contained in § 146.63(c)(1), Customs Regulations (19 CFR 146.63(c)(1)), has been in effect since May 12, 1986, having first been authorized in T.D. 86–16, 51 FR 5040. That weekly entry process has been limited to merchandise which is manufactured or changed into its final form just shortly (within 24 hours) before physical transfer from the zone. This procedure was believed to be especially necessary for assembly-line type manufacturing operations because in these circumstances there would otherwise be little time for examination of the merchandise and furnishing of entry documentation after the merchandise was in its final form but before its physical removal from the zone. Accordingly, under the weekly entry process, the assembly-line operation would not have to be delayed pending acceptance of an entry and Customs examination of the merchandise.

Title VI of the North American Free Trade Agreement Implementation Act (Pub. L. 103–182, 107 Stat. 2057), popularly known as the Customs Modernization Act, was enacted on December 8, 1993. Section 637 of the Customs Modernization Act, which amended 19 U.S.C. 1484 concerning the entry of merchandise generally, provides further statutory support for the weekly 4 entry procedure, in concert with section 3 of the FTZA (19 U.S.C. 81c(a)), which deals specifically with the entry of merchandise from zones.

Since its inception, there have been no major problems associated with the use of weekly entry. Therefore, Customs is proposing to expand the use of the procedure by adding a weekly entry procedure to cover merchandise involved in activities other than manufacturing operations. Also, under the proposed amendment, the weekly entry under both the present procedure and the proposed expanded procedure would cover any seven-day consecutive period (*i.e.*, the weekly period would not be limited to a calendar week).

It is expected that the expanded weekly entry procedure would be available to zones (including subzones) having large quantities of different types of merchandise. A pilot program, implemented in September 1994, to test such an expanded weekly entry procedure at a selected number of zones/subzones has since been evaluated as a success.

Under the proposed expanded procedure, weekly entries and entry summaries would have to be filed electronically through the Automated Broker Interface (ABI). Thus, the participant making entry would have to do so using ABI, or employ an ABI-qualified Customs broker for this purpose. Specifically, the port director would allow the person making entry to file an electronic entry containing the data required on Customs Form 3461 for the estimated removals of merchandise intended to occur during the related weekly period. The electronic entry would be filed prior to any transfers of merchandise from the zone, and an electronic entry summary containing the data required on Customs Form 7501 would be filed within 10 working days after the first day of the weekly period covered by the electronic entry. Payment of applicable duties and taxes would likewise be scheduled for no later than 10 working days after the date of entry, using the Automated Clearinghouse (ACH) as prescribed in § 24.25, Customs Regulations (19 CFR 24.25).

The principal purpose of the proposed expanded weekly procedure, as conducted in a fully paperless environment, is to reduce the number of entries from zones and further expedite the processing of such entries, with the added benefit that zone users would not have to delay their operations pending the acceptance of an entry and Customs examination of the subject merchandise.

Hence, while the expanded weekly entry procedure, like the current weekly manufacturing entry procedure, is a voluntary program, an integral component thereof, under the proposed amendment, would be the use of electronic entry filing. Indeed, electronic entry processing accords precisely with and fully effects the purpose of the program, as described. At the same time, however, zone users not wishing to use the expanded weekly entry may, of course, continue to operate in a zone, and, to this end, if desired, may file paper entries covering individual transfers of merchandise from the zone, inasmuch as electronic entry filing is also a voluntary program (see 19 U.S.C. 1411(b); 19 CFR 143.31).

No retail trade or retail sales within the zone would be permitted through this procedure. Retail trade is prohibited in a zone except as provided in 19 U.S.C. 810(d) of the FTZA.

The person with the right to make entry, who has established an importing history, and who is not delinquent or otherwise remiss in transactions with Customs, would make application to the port director at least 30 days before the expanded weekly entry procedure were to become effective. Each person seeking permission to use the expanded procedure under the proposed section 146.63(c)(2) would have to file an individual application therefor. The application would describe the merchandise to be handled or processed, the accounting and transportation controls exercised over the merchandise, and the kind of activity or operation it would undergo in the zone. The port director would evaluate the application based on the quality of the accounting and transportation controls exercised over the merchandise in the zone, the enforcement risk presented, the type of merchandise imported, Customs knowledge of the business conducted in the zone, and any local criteria developed by the port director. The port director would have to provide written notice of any special local criteria that would be used in evaluating the application.

It is noted that filers eligible for weekly entry under § 146.63(c)(1) would not be required to apply or reapply for participation in that program.

To be approved for expanded weekly entry, the merchandise to be admitted to the zone, its handling or processing therein, and the shipments of such merchandise from the zone, would have to be fairly predictable, continuing and repetitive, and relatively fixed in variety by the type of merchandise and the nature of the business conducted at the site. In addition, the subject merchandise would have to have been preclassified or otherwise have been determined to be risk-free; it could not be restricted or sensitive or of a type which required Customs examination before or at the time of its admission to, or removal from, the zone. Quota-class merchandise would thus be excluded from the program. Also, the records with respect to the merchandise and its handling and/or processing in the zone, if not computerized, would have to be maintained in an organized and readily retrievable manner, and be capable of being accessed by Customs within a reasonable time after due notice.

Additionally, in the case of a general-purpose zone with multiple users, the zone operator would, in writing, have to certify to the port director that he understands the requirements of the expanded weekly entry program, and agree to supervise and monitor the movement of merchandise thereunder. The operator would also have to expressly agree to maintain inventory records that accurately accounted for all transfers of merchandise from the zone related to the respective weekly entry of each person using the procedure therein. The zone operator's written acknowledgement of responsibilities in this regard would be required to be on file with the applicable port director before any application to use the weekly entry procedure could be approved in relation to the zone.

The port director, following his evaluation of the application, would notify the applicant, in writing, of his decision. If the application was denied, the port director would specify the reason for the denial in his reply, and would inform the applicant that such denial may be appealed to the port director for reconsideration. A request for reconsideration may, if denied, be appealed to the Assistant Commissioner, Office of Field Operations, Customs Headquarters. Such appeals must be made within 30 days of the date of the adverse decision being appealed. The port director's decision or the Assistant Commissioner's decision, as applicable, would be issued, in writing, within 30 days of the receipt of the appeal. The Assistant Commissioner's decision would constitute the final Customs determination concerning the application.

If the application were approved, the port director could stay participation in the weekly entry program for a specified reasonable period, should examination of the merchandise or its documentation be needed for any reason.

In addition, the port director could later propose to revoke the approval, if there were a subsequent failure to fulfill the criteria under which the initial approval had been obtained, or if it thereafter became routinely necessary to examine the merchandise or its documentation before or upon admission to, or removal from, the zone, should the merchandise have become restricted or sensitive or otherwise of a type which likewise routinely required Customs examination. A challenge to a proposed revocation of participation in the weekly entry program could be filed with the port director. An adverse decision by the port director could be appealed to the Assistant Commissioner, Field Operations, Customs Headquarters. The Assistant Commissioner's decision in this connection would constitute the final Customs determination concerning the challenge.

It is also proposed to add a new paragraph (d) to § 146.68 to provide for weekly reporting of transfers from a foreign trade zone to a class 9 warehouse (duty-free store), provided the zone grantee or operator is also the class 9 warehouse proprietor. The procedure is similar to the warehouse transfer procedure set out in § 144.34 of the Customs Regulations (19 CFR 144.34).

Comments

Before adopting this proposal, consideration will be given to any written comments that are timely submitted to Customs. Comments submitted will be available for public inspection in accordance with the Freedom of Information Act (5 U.S.C. 552), § 1.4, Treasury Department Regulations (31 CFR 1.4), and § 103.11(b), Customs Regulations (19 CFR 103.11(b)), during regular business days between the hours of 9:00 a.m. and 4:30 p.m. at the Regulations Branch, Franklin Court, 1099 14th Street, N.W., Suite 4000, Washington, D.C.

Regulatory Flexibility Act and Executive Order 12866

As explained in the preamble, the proposed rule is intended to expand electronic entry filing on a weekly basis in foreign trade zones, and thus reduce the number of entry filings from zones as well as automate and expedite the processing of such entries. As such, pursuant to the provisions of the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), it is hereby certified that the proposed amendments set forth in this document, if adopted, will not have a significant economic impact on a substantial number of small entities. Accordingly, they are not subject to the regulatory analysis or other requirements of 5 U.S.C. 603 and 604. Nor do the proposed amendments result in a ''significant regulatory action'' under E.O. 12866.

Paperwork Reduction Act

The collection of information contained in this notice of proposed rulemaking has been submitted to the Office of Management and Budget for review in accordance with the Paperwork Reduction Act of 1995 (44 U.S.C. 3507).

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 control number.

The collection of information in this document is in § 146.63(c). This information is needed and will be used to enforce Customs entry procedures as required by law and to ensure the protection of the revenue. The likely respondents and/or recordkeepers are businesses.

Estimated annual reporting and/or recordkeeping burden: 300 hours.

Estimated average annual burden per respondent/recordkeeper: 30 minutes.

Estimated number of respondents and/or recordkeepers: 600.

Estimated annual frequency of responses: 1.

Comments on the collection of information should be sent to the Office of Management and Budget, Attention: Desk Officer of the Department of the Treasury, Office of Information and Regulatory Affairs, Washington, D.C. 20503. A copy should also be sent to the Regulations Branch, Office of Regulations and Rulings, U.S. Customs Service, 1301 Constitution Avenue, N.W., Washington, D.C. 20229. Comments should be submitted within the same time frame as comments on the substance of the proposal.

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 the 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 startup costs and costs of operations, maintenance, and purchase of services to provide information.

List of Subjects in Part 146

Customs duties and inspection, Exports, Foreign trade zones, Imports, Reporting and recordkeeping requirements.

Proposed Amendment

It is proposed to amend part 146, Customs Regulations (19 CFR part 146), as set forth below.

PART 146—FOREIGN TRADE ZONES

1. The authority citation for part 146 would continue to read as follows:

Authority: 19 U.S.C. 66, 81a-u, 1202 (General Note 20, Harmonized Tariff Schedule of the United States), 1623, 1624.

2. It is proposed to amend § 146.63 by revising paragraph (c) to read as set forth below:

§ 146.63 Entry for consumption.

* * * * *

(c) *Estimated activity*—(1) *Weekly manufacturing.* When merchandise is manufactured or its physical condition as entered (exclusive of packing) is otherwise changed in a zone within 24 hours before physical transfer from the zone for consumption, the port director may allow the person making entry to file an entry on Customs Form 3461 for the estimated removals of merchandise during any consecutive 7-day period (such period is thus not limited to being a calendar week). The Customs Form 3461 must be accompanied by a pro forma invoice or schedule showing the number of units of each type of merchandise to be removed during the weekly period and their zone and dutiable values. Merchandise 13 covered by an entry made under the provisions of this paragraph will be considered to be entered and may be removed only when the port director has accepted the entry on Customs Form 3461. If the actual removals will exceed the estimate for the week, the person making entry shall file an additional Customs Form 3461 to cover the additional units before their removal from the zone. Notwithstanding that a weekly entry may be allowed, all merchandise will be dutiable as provided in § 146.65 of this subpart, with the time of entry being determined as provided in § 141.68 of this chapter. When estimated removals exceed actual removals, that excess merchandise will not be considered to have been entered or constructively transferred from the zone. After acceptance of the weekly entry, and any additional entries required to be filed hereunder, individual transfers of merchandise covered by the entry may be made from the zone.

(2) *Weekly expanded.* Regarding merchandise not qualifying for weekly entry under paragraph (c)(1) of this section, the port director may, upon application, allow the person making entry of such merchandise to file an electronic entry containing the data required on Customs Form 3461 for the estimated removals of merchandise intended to occur during the related weekly period. Such weekly period may cover any consecutive 7-day period and is not limited to being a calendar week. The electronic data submitted must show the number of units of each type of merchandise to be removed during the weekly period and their dutiable values (see § 143.36 of this chapter). Merchandise covered by an electronic entry made under the provisions of this paragraph will be considered to be entered and may be removed from the zone only when the port director has accepted the entry. If the actual removals will exceed the estimate for the week, the person making entry shall file an additional electronic entry to cover the additional units before their removal from the zone. An electronic entry summary containing the data required on Customs Form 7501 must be filed within 10 working days after the first day of the weekly period covered by the electronic entry. Both the weekly entry and the related entry summary must be filed electronically through the Automated Broker Interface, with payment of applicable duties and taxes being scheduled, through the Automated Clearinghouse, for no later than 10 working days after the date of entry (see subpart D, part 143, and § 24.25 of this chapter). Under this weekly entry procedure, all merchandise will be dutiable as provided in § 146.65 of this subpart, with the time of entry being determined as provided in § 141.68 of this chapter. When estimated removals exceed actual removals, such excess merchandise will not be considered to have been entered or constructively transferred from the zone.

(i) *Application required; criteria.* Each person seeking permission to make a weekly zone entry under paragraph (c)(2) of this section must file an individual application therefor. The person must have an established importing history 15 and must not be delinquent or otherwise remiss in transactions with Customs. The written application shall be filed with the port director at least 30 days before the applicant wishes to use the weekly expanded entry procedure. The application must state that weekly entries and entry summaries will be filed with Customs electronically using the Automated Broker Interface; describe the merchandise to be handled or processed citing the Harmonized Tariff Schedule of the United States classification (and providing to Customs changes thereto), describe the accounting and transportation controls exercised over the merchandise, and describe the kind of operation such merchandise will undergo in the zone. The port director will evaluate the application based on the quality of the accounting and transportation controls exercised over the merchandise, the enforcement risk presented, the type of merchandise imported, and Customs knowledge of the business conducted in the zone. The port director shall also consider in his evaluation of the application the following additional criteria:

(A) The merchandise to be admitted to the zone, its handling or processing therein, and the shipments of such merchandise from the zone must be predictable, repetitive, and stable over the long term, and relatively fixed in variety by the type of merchandise and the nature of the business conducted at the site;

(B) The subject merchandise must have been preclassified or otherwise have been determined to be risk-free; such merchandise may not be restricted or sensitive or of a type which requires Customs examination before or at the time of its admission to, or removal from, the zone;

(C) Records with respect to the merchandise and its handling and/or processing in the zone, if not computerized, must be maintained in an organized and readily retrievable manner, and be capable of being produced within a reasonable time after due notice; and

(D) Any other local criteria that the port director considers essential to the application process. (The port director must provide a written announcement of such criteria by a notice posted at the customhouse, or by any other written methods considered appropriate.)

(ii) *Application decision.* The port director shall notify the applicant, in writing, of Customs decision on the application. If the application is denied, the port director shall specify the reason for the denial in his reply, together with what corrective action may be taken, and shall inform the applicant that such denial may be appealed in the manner prescribed in paragraph (c)(2)(v) of this section. The party may not reapply for participation in the weekly entry program until the reason for the denial is resolved. If the application is approved, the party may later apply to amend its application to add merchandise not previously covered therein, for inclusion in its weekly entry program. If a requested amendment is denied, the procedures set forth in this paragraph shall apply.

(iii) *Stay.* If the application to participate in the weekly entry program is approved, the party's use of weekly entry for particular merchandise may thereafter be stayed, for a specified reasonable period, should the port director determine, for any reason, to examine the merchandise or its associated documentation prior to entry, for purposes of verification. A stay of the weekly entry procedure in this regard shall take effect on the date of the port director's letter notifying the party thereof and shall remain in effect for the period specified in that letter, or such earlier date as the port director notifies the party in writing that the reason for the stay has been satisfied. After the stay is lifted, the entry of such merchandise under the weekly entry program may resume.

(iv) *Proposed revocation of approval.* The port director may propose to revoke the approval given under this section, if there is a failure to sustain the criteria in paragraph (c)(2)(i) of this section, or if it thereafter becomes routinely necessary to examine the merchandise or documentation before or upon admission to, or removal from, the zone, because the merchandise has become restricted or sensitive or otherwise of a type which likewise requires examination. The port director shall notify the appropriate party, in writing, specifying in detail the reason for the proposed revocation, and shall inform the party of its right to challenge the proposed revocation action as prescribed in paragraph (c)(2)(v) of this section.

(v) *Appeal of denial or challenge to proposed revocation.* An appeal of a denial of an application under this section, or challenge to the proposed revocation of an approval to use the weekly entry procedure under this section, may be made to the port director issuing the denial or proposed revocation and must be filed within 30 days of the date of the denial or proposed revocation. A denial of an appeal or challenge made to the port director may itself be appealed to the Assistant Commissioner, Office of Field Operations, Customs Headquarters, and must be filed within 30 days of the denial date of the initial appeal or challenge. The 30-day period for filing an appeal or challenge with the port director or with the Assistant Commissioner, Field Operations, as applicable, may be extended for good cause, upon written request by the party for such extension filed with the port director or, in the case of appeals or challenges directed to the Assistant Commissioner, Field Operations, with the Assistant Commissioner or other Customs officer designated by him, within the 30-day period. The port director's decision or the Assistant Commissioner's decision, as applicable, shall be issued, in writing, within 30 working days of the receipt of the appeal or challenge, unless extended with due notification to the party. The Assistant Commissioner's decision shall constitute the final Customs determination concerning the application or challenge.

(vi) *General-purpose zones*—(A) *Operator responsibilities.* In the case of a general-purpose zone with 18a multiple users, not only is paragraph (c)(2)(ii) of this section applicable, but also the zone operator must, in writing, certify to the port director that he understands the requirements of the 19 weekly entry program under paragraph (c)(2) of this section, and agree to supervise and monitor the movement of merchandise thereunder (see § 146.4 of this part). The operator must also expressly agree to maintain inventory records that accurately account for all transfers of merchandise from the zone related to the respective weekly entry of each person using the procedure therein as provided for in §§ 146.4 and 146.21 of this part. The zone operator's written acknowledgement of responsibilities in this regard must be on file with the applicable port director before any application to use the weekly expanded entry procedure may be approved in relation to the zone (see paragraph (c)(2)(i) of this section).

(B) *Bond coverage; operator; person making entry.* The operator's responsibilities under the weekly entry procedure are covered under the Foreign Trade Zone Operator's Bond (see § 113.73 of this chapter). The responsibilities of the person making entry are covered under such party's basic importation and entry bond (see § 113.62 of this chapter).

* * * * *

3. It is proposed to amend § 146.68 by adding a new paragraph (d) to read as follows:

§ 146.68 Transfer for transportation or exportation; estimated production.

* * * * *

(d) *Weekly entry for class 9 warehouse (duty-free store).*

(1) *Requirements for transfer.* Merchandise that 20 qualifies for entry into a class 9 warehouse (duty-free store) pursuant to § 19.36(e) of this chapter, and subject also to § 146.64 of this subpart, may be transferred from a zone for that purpose under a weekly entry procedure, provided:

(i) The zone operator or grantee is the same party, or shares common ownership with, the class 9 warehouse proprietor (hereinafter called ''the party''); and

(ii) The party utilizes a Customs approved centralized inventory control system that shows the location of all the zone and warehoused merchandise at all times, including merchandise in transit.

(2) *Procedure.* The following weekly entry procedure is to be utilized for qualifying merchandise:

(i) The party shall file electronically a weekly entry permit to enter the merchandise with the port director on Customs Form 7501 for the estimated removal during any consecutive 7-day period, along with a *pro forma* invoice or schedule pursuant to § 146.63(c)(1) of this subpart.

(ii) Upon acceptance of the permit by the port director, the party may effect transfers of the merchandise from the zone to the warehouse during the 7-day period.

(iii) Both an amended warehouse entry and warehouse withdrawal for immediate exportation, covering the 21 merchandise actually removed from the zone to the warehouse during the period covered by the permit, will be filed by the close of the second business day following the end of the period.

Approved: February 7, 1997.

George J. Weise,

Commissioner of Customs, Deputy Assistant

John P. Simpson,

Secretary of the Treasury.

[FR Doc. 97–6522 Filed 3–13–97; 8:45 am]

BILLING CODE 4820–02–P

DEPARTMENT OF LABOR

Occupational Safety and Health Administration

29 CFR Part 1915

[Docket No. S–051]

RIN 1218–AB51

Safety Standards for Fire Protection for Shipyard Employment

AGENCY: Occupational Safety and Health Administration (OSHA), U.S. Department of Labor.

ACTION: Notice of public meeting.

SUMMARY: The Occupational Safety and Health Administration (OSHA) is announcing a public meeting of the Fire Protection for Shipyard Employment Negotiated Rulemaking Advisory Committee. Membership for this committee has been drawn from shipyard operators, labor, professional associations, public interests and government agencies. Members of the Committee represent the interests of all groups interested in, or significantly affected by, the outcome of the rulemaking.

DATES: The public meeting will be held on April 8 through April 10, 1997. The meetings will run from 9:00 a.m. to approximately 4:00 p.m. daily.

ADDRESSES: The public meeting will be held at Bollinger Shipyard, 20 miles east of Thibodaux on Hwy. 308, Lockport, Louisiana, Telephone: 505–532–2554.

Any written comments in response to this notice should be sent, in quadruplicate, to the following address: U.S. Department of Labor, OSHA, Docket Office, Docket S–051. Room N–2625, 200 Constitution Ave., N.W., Washington, D.C. 20210; Telephone: 202–219–7894.

FOR FURTHER INFORMATION CONTACT: Ms. Bonnie Friedman, U.S. Department of Labor, OSHA, Office of Information and Consumer Affairs, Room N–3647, 200 Constitution Ave., N.W., Washington, D.C. 20210; Telephone: 202–219–8151.

SUPPLEMENTARY INFORMATION:

I. Background

OSHA has decided to use the negotiated rulemaking (Neg/Reg) process to develop a proposed standard for fire protection covering all shipyard employment. The shipyard stakeholders from all sectors strongly support consensual rulemaking efforts like negotiated rulemaking. OSHA believes this process will result in a proposed standard whose provisions will effectively protect employees working throughout the shipyard. (See OSHA's Notice of Intent to Form a Negotiated Rulemaking Committee to Develop a Proposed Rule on Fire Protection in Shipyard Employment, 61 FR 28824, June 6, 1996, for a detailed explanation of why OSHA is using negotiated rulemaking to develop its proposed standard and for general information on the negotiated rulemaking process). The goal of this negotiated rulemaking is a proposed rule and supporting documentation that all members will support.

The initial meeting of this Advisory Committee was held in Portland, Oregon on October 16 and 17, 1996. The members were introduced and the negotiated rulemaking process and the legal requirements for OSHA rulemaking were explained to them. Ground rules for this Committee were adopted. In addition, the Committee set forth substantive issues that needed to be resolved, established work groups and began discussing scope and application, fire prevention and fire fighting.

The last meeting of this Advisory Committee took place in Jacksonville, Florida, February 4 through February 6, 1997. The Committee continued with the issues as developed into work groups during the first meeting: fire watches, fire response, safe work practices, and fire protection.

II. The Key Issues in This Rulemaking

OSHA expects that key issues to be addressed as part of these negotiations will include: scope and application; controls and work practices; fire brigades; written fire plans; technological advances; costs of fire protection; and appendices.

III. Agenda for the April 8–10, 1997, Meeting

1. The meeting will be opened and the roll taken.

2. The minutes from the February 1997, Jacksonville, Florida, meeting will be presented for acceptance by the Committee.

3. The tentative agenda for this meeting will be reviewed and changes made, if necessary.

4. The ''Fire Watches'' work group draft will be presented to the Committee.

5. The ''Scope and Application'' section of the preamble will be presented to the Committee for acceptance.

6. The Work group chairpersons will report on the status of their assignments.

7. The Committee will break into work group sessions as needed throughout the meeting.

8. The Committee will establish the time and date for the next meeting.

The Advisory Committee's Facilitator, relying on the information presented to him by OSHA as well as the considerable input from the various interests during convening efforts, will identify and present other substantive issues to be resolved by this Committee, as time permits. OSHA requests that all interested parties bring their calendars to facilitate the development of a tentative schedule of committee meetings, site visits and work group meetings.

IV. Public Participation

All interested parties are invited to attend this public meeting at the time and place indicated above. No advance registration is required. Seating will be available to the public on a first-come, first-served basis. Individuals with disabilities wishing to attend should contact Ms. Theda Kenney at (202) 219–8061 to obtain appropriate accommodations no later than March 21, 1997.

The Facilitator of the Committee will decide to what extent oral presentations by members of the public may be permitted at the meeting. Oral presentations may include statements of fact and opinions, but shall not include any questioning of the Committee Members or other participants unless these questions have been specifically approved by the Facilitator.

Part 1912 of Title 29 of the Code of Federal Regulations will apply generally. The reporting requirements of § 1912.33 have been changed pursuant to § 1912.42 to help meet the special needs of this Committee. Specifically, § 1912.33 requires that verbatim transcripts be kept of all advisory committee meetings. Producing a coherent transcript requires a certain degree of formality. The Assistant Secretary therefore has determined pursuant to § 1912.42 that such formality might interfere with the free exchange of information and ideas during the negotiations, and that the OSH Act would be better served by simply requiring detailed minutes of the proceedings without a formal transcript.

Minutes of the meetings and materials prepared for the Committee will be available for public inspection at the OSHA Docket Office, N–2625, 200 Constitution Ave., NW., Washington, DC 20210; Telephone: 202–219–7894.

Any written comments should be directed to Docket No. S–051, and sent in quadruplicate to the following address: U.S. Department of Labor, Occupational Safety and Health Administration, Docket Office, Room N–2625, 200 Constitution Ave., NW., Washington, DC 20210; Telephone 202–219–7894.

Authority: This document was prepared under the direction of Greg Watchman, Acting Assistant Secretary of Labor for Occupational Safety and Health, U.S. Department of Labor, 200 Constitution Avenue, NW., Washington, DC 20210, pursuant to section 3 of the Negotiated Rulemaking Act of 1990, 104 Stat. 4969, Title 5 U.S.C. 561 *et seq.*; and Section 7(b) of the Occupational Safety and Health Act of 1970, 84 Stat. 1597, Title 29 U.S.C. 656.

Signed at Washington, DC, this 10th day of March 1997.

Greg Watchman,

Acting Assistant Secretary.

[FR Doc. 97–6515 Filed 3–13–97; 8:45 am]

BILLING CODE 4510–26–M

OCCUPATIONAL SAFETY AND HEALTH REVIEW COMMISSION

29 CFR Parts 2200, 2203, and 2204

Revisions to Procedural Rules Governing Practice Before the Occupational Safety and Health Review Commission

AGENCY: Occupational Safety and Health Review Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: This document proposes several revisions to the procedural rules governing practice before the Occupational Safety and Health Review Commission. Although most of the revisions are technical and clarifying in nature, this proposal also contains several significant changes to Commission practice and procedure.

DATES: Comments must be received by April 14, 1997.

FOR FURTHER INFORMATION CONTACT: Earl R. Ohman, Jr., General Counsel, (202) 606–5410, Occupational Safety and Heath Review Commission, 1120 20th St., N.W., Ninth Floor, Washington, DC 20036–3419.

SUPPLEMENTARY INFORMATION: This document proposes substantial revisions to the procedural rules governing practice before the Occupational Safety and Health Review Commission. Generally, revisions to the Commission's rules of procedure are not subject to the provisions of the Administrative Procedure Act requiring notice and opportunity for comment (5 U.S.C. 553(b)(3)(A)). However, because these revisions will have some effect upon the nature of practice before the Commission and because the Commission values the views of those who appear before it, the Commission invites public comment, especially from those employers and attorneys who will be most effected by these amendments.

1. Service and Notice

The Commission proposes to amend Rule 7(g) by revising the language in the form at the end of the rule to read ''All pleadings relevant to this matter may be inspected at:'' This change conforms the form to the language in the first paragraph of the rule and should have no significant impact on Commission practice.

2. Facsimile Transmission

The Commission would amend Rule 8(f) to require that a document can be filed with the Commission by facsimile transmission only when all of the parties are also served by fax. This would prevent confusion regarding the time of filing and, therefore, the applicability of the 3-day mail box rule.

3. Claims of Privilege

Currently, Rule 11(c) allows a party fifteen days to respond to another party's claim of privilege. The Commission finds no reason to conclude that more time is required to respond to a claim of privilege than to respond to any other motion. Accordingly, the Commission proposes to amend its rule to require that the time for responding to such claims be ten days, the same as any other motion. Of course, where good cause is shown, the Commission and its Judges always have the discretion to extend the time for the filing of such responses.

4. Opposition to Motions

As currently written, Rule 40(a) requires only that the moving party state whether it is aware of any opposition to a motion. This requirement is not useful, however, unless the moving party is required to consult with the opposing party regarding the motion prior to filing. Therefore, the Commission proposes to amend the rule to require that the moving party contact the other parties to determine whether there is any opposition to a motion.

5. Subpoenas

The Commission would add a new Rule 57(b), to explicitly allow subpoenas to be served by certified mail with return receipt, or by leaving a copy of the subpoena at the named person's principal place of business or residence. Currently, the Commission applies Federal Rule of Civil Procedure 45(b)(1) which provides only for personal service. It is the opinion of the Commission that any benefit obtained by requiring personal service does not justify the additional expense to the parties. The Commission notes that the methods of service specified on the reverse of its current subpoena forms do not comport with Federal Rule of Civil Procedure 45. The Commission's subpoena forms would be revised to coincide with new Rule 57(b).

6. Notification of Hearing

In accord with its desire to shorten, insofar as practicable, the time needed to process cases, the Commission proposes to amend Rule 60 to reduce the minimum time for a notice of hearing from thirty to twenty days. This change is proposed to give the Commission's Judges more flexibility to resolve simpler cases. The Commission does not expect that this change will affect a large number of cases.

7. Elimination of 20-day Transmittal Period for Judges' Decisions

The Commission proposes to amend Rule 90(b)(2) to eliminate the twenty day transmittal period for Judges' decisions. This twenty day period was instituted at a time when the Commission's case load was substantially heavier and the Commission was burdened by last-minute petitions for discretionary review.

With the reduction in its case load, the Commission finds that this interim twenty day period is no longer necessary. The Commission has found that petitions filed within twenty days of docketing of the Judge's decision, as required by Rule 91(b), receive the full attention necessary to determine if Commission review is warranted. While this twenty day interim period between transmittal of the decision to the party and its official docketing by the Commission gave the parties an opportunity to call to the Judge's attention typographical and other technical or clerical errors, the Commission believes that such corrective action is already authorized by Rule 90(b)(3). In sum, the Commission finds that, under current case load conditions, the twenty day interim period serves more to delay than to facilitate the processing of Commission cases. Rule 91(b) would be amended to conform with the elimination of the twenty day interim period.

8. Number of Copies Submitted to the Commission

The Commission would amend Rules 8(d)(2), 91(h) and 93(h) to require that when a case is before the Commission the original plus eight copies of a petition for review, brief or other document be filed. The Commission has found that the four copies required under the current rule are inadequate. As as result, the Commission spends considerable time and incurs substantial expense to make the necessary copies. This amendment would rectify the situation.

9. Amendments to the Commission's Rules Implementing the Equal Access to Justice Act

To conform to recent amendments to the EAJA, the Commission would amend its EAJA Rule 107 to change the hourly rate from $75 per hour to $125 per hour.

The Commission would also amend EAJA Rule 301 to conform to the Commission decision in *Asbestos Abatement Consultation and Engineering,* 15 BNA OSHC 1252, 1254–56, 1991–93 CCH OSHD ¶ 29,464, pp. 39,731–32 (No. 87–1522, 1991), in which it held that applications for EAJA awards must be *received* by the Commission within thirty days of the final order date. The current rule requires that the application be filed in accordance with Commission Rules 7 and 8, §§ 2200.7 and 2200.8, and Rule 8(e) states that filing is effective upon mailing.

The holding in *Asbestos Abatement* relied in large part on federal appellate decisions interpreting the filing time limits of EAJA as requiring that the applications be actually received by the agency within the thirty day deadline. These federal courts based their interpretation on both the actual language of the EAJA and the doctrine that statutes waiving sovereign immunity be strictly construed. *E.g.* Sonicraft, Inc. v. *NLRB,* 814 F.2d 385 (7th Cir. 1987); *Monark Boat Co.* v. *NLRB,* 708 F.2d 1322, 1328–9 (8th Cir. 1983).

The Commission notes that in *Tri-State Steel Constr. Co.*, 17 BNA OSHC 1769, 1996 CCH OSHD ¶ 31,145 (No. 93–0512, 1996) (consolidated), the Commission, relying on the Supreme Court decision in *Irwin* v. *Veterans Admin.*, 498 U.S. 89 (1990), held that the filing deadline in the EAJA was not jurisdictional and was subject to equitable tolling because the employer there relied, to its detriment, on Commission Rule 301 which had not been changed to conform to the filing requirements as set forth in *Asbestos Abatement.* However, *Asbestos Abatement* remains good law and, with this proposed change, the rules will be consistent with it.

List of Subjects

29 CFR Part 2200

Hearing and appeal procedures, Administrative practice and procedure.

29 CFR Part 2203

Sunshine Act, Information, Public meetings.

29 CFR Part 2204

Administrative practice and procedure, Equal access to justice.

Text of Amendment

For the reasons set forth in the preamble, the Occupational Safety and Health Review Commission proposes to amend Title 29, Chapter XX, Parts 2200, 2203 and 2204 of the Code of Federal Regulations as follows:

PART 2200—[AMENDED]

1. The authority citation continues to read as follows:

Authority: 29 U.S.C. 661(g), unless otherwise noted.

2. Section 2200.7 is amended by revising paragraph (g) to read as follows:

§ 2200.7 Service and notice.

In § 2200.7(g) remove the words ''All papers relevant to this matter may be inspected:'' and add in their place the words ''All pleadings relevant to this matter may be inspected at:''

3. Section 2200.8 is amended by revising paragraph (d)(2) and the first sentence of paragraph (f)(1) to read as follows:

§ 2200.8 Filing.

* * * * *

(d) *Number of copies.*

* * * * *

(2) *Number of copies.* If a case is before the Commission for review, the original and eight copies of a document shall be filed.

* * * * *

(f) *Facsimile transmissions.* (1) Any document may be filed with the Commission or its Judges by facsimile transmission only if the parties are also served by facsimile transmission. * * *

* * * * *

4. Section 2200.11 is amended by revising the first sentence of paragraph (c) to read as follows:

§ 2200.11 Protection of claims of privilege.

* * * * *

(c) *Opposition to the claim.* A party opposing a claim of privilege, or asserting a substantial need for disclosure in the event a qualified privilege exists, must do so within the time for responding to motions set forth in § 2200.40(c) but, if the motion is made during a hearing, the Judge may prescribe a shorter time for a response or require that the response be made during the hearing. * * *

* * * * *

5. Section 2200.40 is amended by revising the last sentence of paragraph (a) to read as follows:

§ 2200.40 Motions and requests.

(a) *How to make.* * * * Prior to filing a motion, the moving party shall contact the other parties to the action to determine whether they intend to oppose the motion and shall state in the motion any opposition of which the moving party is aware.

* * * * *

6. In § 2200.57 paragraphs (b)–(d) are redesignated (c)–(e) and a new paragraph (b) is added to read as follows:

§ 2200.57 Issuance of subpoenas; petitions to revoke or modify subpoenas; right to inspect or copy data.

* * * * *

(b) *Service of subpoenas.* A subpoena may be served by any person who is not a party and is not less than 18 years of age. Service of a subpoena upon a person named therein may be made by service on the person named, by certified mail return receipt requested, or by leaving a copy at the person's principal place of business or at the person's residence with some person of suitable age and discretion residing therein.

* * * * *

7. Section 2200.60 is amended by revising the first sentence to read as follows:

§ 2200.60 Notice of hearing; location.

Except by agreement of the parties, or in an expedited proceeding under § 2200.103, notice of the time, place, and nature of the first setting of a hearing shall be given to the parties and intervenors at least 20 days in advance of the hearing.

* * * * *

8. Section 2200.90 is amended by revising the first sentence of paragraph (b)(2) to read as follows:

§ 2200.90 Decisions of judges.

* * * * *

(b) * * *

(2) *Docketing of Judge's report by Executive Secretary.* When the Judge transmits the decision to the parties, the Judge shall file a report with the Executive Secretary for docketing. * * *

* * * * *

9. Section 2200.91 is amended by revising paragraphs (b) and (h) to read as follows:

§ 2200.91 Discretionary review; petitions for discretionary review; statements in opposition to petitions.

* * * * *

(b) *Petitions for discretionary review.* A party adversely affected or aggrieved by the decision of the Judge may seek review by the Commission by filing a petition for discretionary review directly with the Executive Secretary. A petition shall be filed within 20 days after the date of docketing of the Judge's report. * * *

* * * * *

(h) *Number of copies.* An original and eight copies of a petition or a statement in opposition to a petition shall be filed.

10. Section 2200.93 is amended by revising paragraph (h) to read as follows:

§ 2200.93 Briefs before the Commission.

* * * * *

(h) *Number of copies.* The original and eight copies of a brief shall be filed. See § 2200.8(d)(2).

* * * * *

§§ 2200.11; 2200.57; 2200.67; 2200.101 [Amended]

11. All references to ''subpena'' are revised to read ''subpoena'' and all references to ''subpenas'' are revised to read ''subpoenas'' in the following places:

(a) Section 2200.11(e);
(b) Section 2200.57;
(c) Section 2200.67 (b) and (c);
(d) Section 2200.101(c)(2)

PART 2203—[AMENDED]

1. The authority for Part 2203 continues to read as follows:

Authority: 29 U.S.C. 661(g); 5 U.S.C. 552b(d)(4); 5 U.S.C. 552b(g)

2. Part 2203 is amended as follows:

§ 2203.3 [Amended]

Section 2203.3(b)(10) is revised by changing the reference to ''subpena'' to read ''subpoena.''

PART 2204—[AMENDED]

1. The authority for Part 2204 continues to read as follows:

Authority: Sec. 203(a)(1), Pub. L. 96–481, 94 Stat. 2325 (5 U.S.C. 504(c)(1)); Pub. L. 99–80, 99 Stat. 183

2. Section 2204.107 is amended by revising the first sentence of paragraph (b) to read:

§ 2204.107 Allowable fees and expenses.

* * * * *

(b) An award for the fee of an attorney or agent under these rules shall not exceed $125 per hour, unless the Commission determines by regulation that an increase in the cost of living or a special factor, such as the limited availability of qualified attorneys or agents for Commission proceedings, justifies a higher fee. * * *

* * * * *

3. Section 2204.301 is revised to read as follows:

§ 2204.301 Filing and service of documents.

An EAJA application is deemed to be filed only when received by the Commission. In all other respects, an application for an award and any other pleading or document related to an application shall be filed and served on all parties to the proceeding in accordance with §§ 2200.7 and 2200.8, except as provided in § 2204.202(b) for confidential financial information.

Dated: March 6, 1997.

Stuart E. Weisberg,

Chairman.

Dated: March 6, 1997.

Velma Montoya,

Commissioner.

Dated: March 6, 1997.

Daniel Guttman,

Commissioner.

[FR Doc. 97–6362 Filed 3–13–97; 8:45 am]

BILLING CODE 7600–01–M

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 52 and 81

[IN77–1; FRL–5709–2]

Approval and Promulgation of Air Quality Implementation Plans, and Designation of Areas for Air Quality Planning Purposes; Indiana

AGENCY: United States Environmental Protection Agency (USEPA).

ACTION: Proposed rule.

SUMMARY: The USEPA is proposing to approve the ozone maintenance plan submitted as a State Implementation Plan (SIP) revision request and the redesignation request submitted by the State of Indiana for the purpose of redesignating Vanderburgh County (Evansville) from marginal nonattainment to attainment for ozone. Ground-level ozone, commonly known as smog, is an air pollutant which forms on hot summer days and which harmfully affects lung tissue and breathing passages. The redesignation to attainment of the health-based ozone air quality standard is based on a request from the State of Indiana to redesignate this area and approve its maintenance plan, and on the supporting data the State has submitted in support of the requests. Under the Clean Air Act, a designation can be changed if sufficient data are available to warrant such a change, and a maintenance plan is put in place which is designed to ensure the area maintains the ozone air quality standard for the next ten years.

DATES: Comments must be received by May 13, 1997.

ADDRESSES: Copies of the revision request and USEPA's analysis (Technical Support Documents) are available for inspection at the following address:

U.S. Environmental Protection Agency, Region 5, Air and Radiation Division, 77 West Jackson Boulevard, Chicago, Illinois 60604. (It is recommended that you telephone Edward Doty at (312) 886–6057 before visiting the Region 5 Office.)

Written comments should be sent to:

J. Elmer Bortzer, Chief, Regulation Development Section, Air Programs Branch (AR–18J), U.S. Environmental Protection Agency, 77 West Jackson Boulevard, Chicago, Illinois 60604.

FOR FURTHER INFORMATION CONTACT: Edward Doty at (312) 886–6057.

SUPPLEMENTARY INFORMATION: On November 15, 1990, the Clean Air Act Amendments of 1990 were enacted. Pub. L. 101–549, codified at 42 U.S.C. 7401–7671q. Pursuant to section 107(d)(4)(A) of the Clean Air Act (CAA or the Act), Vanderburgh County (Evansville) was designated as nonattainment for ozone and was classified as marginal (see 56 FR 56694 (November 6, 1991)).

I. Background

The Indiana Department of Environmental Management (IDEM) submitted an ozone redesignation request and maintenance plan for Vanderburgh County (Evansville) on November 4, 1993. On July 8, 1994 (59 FR 35044), the United States Environmental Protection Agency (USEPA) published a direct final rulemaking approving the redesignation of Vanderburgh County to attainment of the National Ambient Air Quality Standard (NAAQS) for ozone. On the same day, a proposed rulemaking was also published in the Federal Register which established a 30-day public comment period for the redesignation approval and noted that, if adverse comments were received regarding the direct final rulemaking, the USEPA would withdraw the direct final rulemaking and would address the adverse comments through a revised final rulemaking. The USEPA received adverse comments, and published a withdrawal of the direct final rulemaking on August 26, 1994 (59 FR 44040).

Subsequent to the July 8, 1994 direct final rulemaking, the USEPA was informed by the IDEM that a possible violation of the ozone NAAQS had been monitored at a privately-operated industrial site owned by the Aluminum Corporation of America (Alcoa) in Warrick County. (At the time IDEM contacted the USEPA concerning the possible violation, the State had not yet completed quality assurance of the data. The violation, as noted below, was subsequently quality-assured.) Warrick County (designated as attainment for ozone) adjoins Vanderburgh County to the east. Because Warrick County can be considered to be a nearby area downwind of Vanderburgh County on certain days, the USEPA questioned whether the monitored violation in Warrick County should be considered in any subsequent rulemaking on the redesignation of Vanderburgh County. The IDEM indicated its intent to investigate the high ozone values, and requested that the USEPA not act on the redesignation petition pending the outcome of that technical investigation. IDEM completed its investigation and submitted the results to the USEPA on June 5, 1995. IDEM's investigation concluded that the Alcoa data are unusual, are biased high (relative to peak ozone concentrations at other monitors in the area during the May through June, 1994 time period), and are not representative of the Vanderburgh County nonattainment area. IDEM recommended that the USEPA should proceed with the redesignation of Vanderburgh County to attainment so that the maintenance plan could become federally enforceable.

The USEPA Technical Support Document (TSD) for this proposed rulemaking: (1) summarizes and evaluates the redesignation request; (2) analyzes recent State data for monitors inside and outside of the Evansville nonattainment area; (3) responds to public comments on the July 8, 1994 rulemaking; and (4) reviews the State's and public's submittals and technical concerns regarding the monitored ozone NAAQS violation in Warrick County and its impact on the redesignation of Vanderburgh County.

This notice summarizes USEPA's review and analysis of the redesignation request. Details of the review and analysis are contained in USEPA's TSD. Comments received from the public with regard to the July 8, 1994 proposed rulemaking and received subsequent to that proposal are also addressed in this notice.

II. USEPA'S General Comments and Conclusions

After a review of all available information, the USEPA believes it is reasonable to repropose the redesignation of Vanderburgh County to attainment and, thus, allow for formal public review and comment on IDEM's technical support document and USEPA's evaluation. As described below, the redesignation request for Vanderburgh County satisfies the specific criteria of section 107(d)(3)(E). A critical issue, however, concerns the ozone monitoring data indicating a violation of the ozone standard in Warrick County, Indiana, a county that is part of the Evansville Metropolitan Statistical Area (MSA) but is not part of the Evansville ozone nonattainment area. (The Evansville MSA consists of Posey, Vanderburgh, and Warrick Counties in Indiana and Henderson County in Kentucky. The Evansville ozone nonattainment area consists solely of Vanderburgh County. For the Evansville area, which is classified as marginal nonattainment for ozone, the USEPA does not require the entire MSA to be designated as nonattainment for ozone.) Those data, which are discussed in detail later in this notice, demonstrate that Warrick County has experienced a current violation of the ozone NAAQS based on five exceedances of the ozone standard (0.12 parts per million, one-hour averaged, not to be exceeded on average more than one day per year at any monitoring site in the area under consideration) that were monitored in May and June of 1994. No violations of the ozone NAAQS have been monitored in Vanderburgh County itself since the 1988–1990 period.

The validity and significance of the monitoring data showing a violation at the Alcoa site in Warrick County has been the subject of much review and analysis by both the IDEM and the USEPA. In its TSD reviewing the Alcoa data and data from other ozone monitoring sites in the area during the period of the 1990 ozone NAAQS violation, the IDEM contends that, although the Alcoa data have met quality assurance criteria, the data are unusual, are biased high, and are not representative of the Evansville nonattainment area. The USEPA, however, has reviewed the data and has concluded that the data have met the USEPA's quality assurance criteria, are valid, are acceptable for review of attainment status.

The USEPA has also reviewed the data and other pertinent information in an effort to determine whether and to what extent emissions from Vanderburgh County contributed to the ozone NAAQS violation in Warrick County. The USEPA conducted this evaluation because Warrick County adjoins Vanderburgh County and because section 107(d)(1)(A)(i) of the Clean Air Act defines a nonattainment area as an area that either itself violates a standard that contributes to a standard violation in a nearby area. If the USEPA were to conclude that Evansville does contribute significantly to nonattainment of the ozone standard in Warrick County, the language of section 107(d)(1)(A)(i) would present an obstacle to taking final action redesignating Vanderburgh County to attainment.

The USEPA intends to take final action approving the redesignation of Vanderburgh County to attainment if any of the following three events occur. First, if Warrick County attains the ozone standard prior to final action by the USEPA on this redesignation request, the USEPA would no longer need to consider the issue of any possible contribution of Vanderburgh County to violations in Warrick County. This could occur following the 1997 ozone season (April through October) as the standard violation in Warrick County was monitored in 1994; and USEPA's methodology for determining attainment of the ozone NAAQS involves the consideration of data only from the most recent three years. Second, the USEPA could take final action approving the Vanderburgh County redesignation request if it determines that Vanderburgh County does not significantly contribute to an ozone nonattainment problem in Warrick County. Third, the USEPA could approve the Vanderburgh County redesignation request if the USEPA determines that the information available is not sufficient to determine whether or not Vanderburgh County contributes significantly to a nonattainment problem in Warrick County.

To complete its review process, the USEPA also seeks comment on whether or not the Warrick County ozone standard violation data should be excluded from consideration of the Vanderburgh County ozone attainment status. Comments on this issue will allow the public to address IDEM's proposed basis for approval of the Evansville redesignation request. In addressing this issue, commenters should also take into consideration and respond to the facts that the Warrick County ozone standard violation has been quality assured and that the Clean Air Act and USEPA policy require the consideration of the ozone standard violation when reviewing the attainment status of Vanderburgh County.

The USEPA requests comment on all of these issues in light of the information and data in the docket, including the analyses of the data and other information performed by IDEM and USEPA. The USEPA will carefully and fully evaluate those comments and the issues they raise before taking final action regarding the Vanderburgh County redesignation request.

At this time, the state of the science of predicting and understanding the formation and transport of ozone in the Evansville MSA is incomplete. The USEPA does not have the benefit of ozone modeling information for the Evansville MSA, such as would be provided by the use of the Urban Airshed Model. The USEPA recognizes that the State of Indiana, along with 36 other states, is actively involved in the super-regional ozone modeling analyses being conducted through the Ozone Transport Assessment Group (OTAG). Although the Evansville MSA has been included in the national Regional Oxidant Modeling (ROM) modeling domain and in the OTAG modeling domain, the scope of these models is regional in nature and is not conclusive as to the impact of emissions from Vanderburgh County on ozone formation in the Evansville MSA.

The USEPA encourages the State of Indiana to follow through on its commitment to implement early the contingency measures provided for in the maintenance plan for Vanderburgh County and to consider emission controls beyond the boundaries of Vanderburgh County as a means to assure future good air quality in Warrick County. The USEPA notes the commitment made by the State of Indiana to implement contingency measures even prior to their being triggered under provisions of the maintenance plan and to work with the local Evansville community and surrounding areas to adopt additional emission control programs and regulations and to submit these regulations as a revision to the State implementation plan. The USEPA is relying on the State to follow through on that commitment in order to obtain additional emission reductions that will provide greater assurance of good air quality in the Evansville MSA in the future.

In support of this approach, the IDEM has attended meetings with the Evansville community to discuss the ozone concentrations in the area and appropriate control measures to reduce emissions of ozone forming chemicals. A broad-based community group called the Action Committee for Ozone Reduction Now (ACORN) has recommended four measures to be voluntarily adopted by the State and local authorities to reduce emissions. These four measures are: (1) high volume low pressure paint gun change outs for auto body refinishing and paint spraying operations; (2) Stage I gasoline vapor recovery; (3) pollution prevention and education task force; and (4) less polluting gasoline. ACORN suggests that all remedial ozone reduction measures shall apply to people and industry in Vanderburgh County and adjacent counties. The USEPA believes that these measures applied in the Evansville area will contribute to continued attainment of the ozone standard in Vanderburgh County and will contribute to improved air quality in the downwind communities.

The USEPA recently published an Advanced Notice of Intent (ANI) describing the OTAG process referred to above and setting forth USEPA's plans to take action in 1997 to require that control measures be adopted and implemented to reduce emissions that are transported to other areas and contribute to high ozone concentrations downwind of the emission sources (see 62 FR 1420 (January 10, 1997)). IDEM has committed to participate actively in this process and to implement emission control measures resulting from this process. This effort should lead to regional ozone precursor reductions that may significantly reduce the transport of ozone into the Evansville area and may result in further emission reductions within the Evansville area itself. A redesignation of Evansville to attainment would not impede the implementation of any emission controls resulting from the OTAG process or USEPA's anticipated actions.

The USEPA believes that emission reductions occurring as a result of USEPA's anticipated actions in 1997, early implementation of contingency measures committed to by the State of Indiana, and implementation of measures proposed by ACORN will provide additional assurance that the air quality in Vanderburgh County and its downwind environs will be improved, and that future violations of the ozone NAAQS will not occur in these areas.

III. Technical Review

A. Redesignation Review Criteria

Under the CAA, designations can be changed if sufficient data are available to warrant such change. The CAA provides the requirements for redesignating a nonattainment area to attainment. Specifically, section 107(d)(3)(E) provides for redesignation if: (1) the Administrator determines that the area has attained the National Ambient Air Quality Standard (NAAQS); (2) the Administrator has fully approved the applicable implementation plan for the area under section 110(k); (3) the Administrator determines that the improvement in air quality is due to permanent and enforceable reductions in emissions resulting from implementation of the applicable implementation plan and applicable Federal air pollutant control regulations and other permanent and enforceable reductions; (4) the Administrator has fully approved a maintenance plan for the area as meeting the requirements of section 175A; and (5) The State containing such area has met all requirements applicable to the area under section 110 and part D.

The USEPA has provided guidance on processing redesignation requests in documents including the following:

1. ''Part D New Source Review (part D NSR) Requirements for Areas Requesting Redesignation to Attainment,'' Mary D. Nichols, Assistant Administrator for Air and Radiation, October 14, 1994.

2. ''Use of Actual Emissions in Maintenance Demonstrations for Ozone and Carbon Monoxide (CO) Nonattainment Areas,'' D. Kent Berry, Acting Director, Air Quality Management Division, November 30, 1993.

3. ''State Implementation Plan (SIP) Requirements for Areas Submitting Requests for Redesignation to Attainment of the ozone and Carbon Monoxide (CO) National Ambient Air Quality Standards (NAAQS) On or after November 15, 1992,'' Michael H. Shapiro, Acting Assistant Administrator for Air and Radiation, September 17, 1993.

4. ''State Implementation Plan (SIP) Actions Submitted in Response to Clean Air Act (ACT) Deadlines,'' John Calcagni, Director, Air Quality Management Division, October 28, 1992.

5. ''Procedures for Processing Requests to Redesignate Areas to Attainment,'' John Calcagni, Director, Air Quality Management Division, September 4, 1992.

6. ''Contingency Measures for Ozone and Carbon Monoxide (CO) Redesignations,'' G.T. Helms, Chief, Ozone/Carbon Monoxide Programs Branch, June 1, 1992.

7. State Implementation Plans; General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990 (57 FR 13498), April 16, 1992.

B. Review Of The Redesignation Request

1. The area must have attained the Ozone NAAQS.

For ozone, an area may be considered as attaining the NAAQS if there are no violations, as determined in accordance with the regulation codified at 40 CFR § 50.9, based on three (3) consecutive calendar years of quality assured monitoring data. A violation occurs when the ozone air quality monitoring data show greater than one (1.0) average expected exceedance per year at any site in the area. An exceedance occurs when the maximum hourly ozone concentration exceeds 0.12 parts per million (ppm). The data should be collected and quality-assured in accordance with 40 CFR part 58, and recorded in the Aerometric Information Retrieval System (AIRS) in order for it to be available to the public for review.

The redesignation request for Evansville relies on ozone monitoring data for the years 1990 through 1996, to show that Evansville is attaining the NAAQS for ozone. IDEM has collected quality assured data in Vanderburgh County at two locations (or monitoring sites) for the period of 1990 through 1996 showing attainment of the ozone standard. In general, the USEPA considers the three most recent years of data for a redesignation request and the three most recent years of data from these two sites have no exceedances of the ozone standard. These data are quality assured and are recorded in the AIRS. In addition, ozone monitoring data has been collected at two sites in Warrick County as downwind monitoring sites for Evansville. The two monitors at Boonville and Tecumseh High Schools also demonstrate attainment of the ozone standard. The PSD industrial monitoring site at Alcoa has collected valid data which recorded a violation of the ozone standard for the most recent three years of data (1994–1996).

As discussed above, there are issues concerning the role of emissions from Vanderburgh County in contributing to a violation of the ozone NAAQS monitored in 1994 in Warrick County. As stated there, the USEPA is requesting comment on these issues.

2. The Area must have a fully approved SIP under Section 110(k); and the Area must have met all applicable requirements under Section 110 and Part D.

Before Vanderburgh County (Evansville) may be redesignated to attainment for ozone, it must have fulfilled the applicable requirements of section 110 and Part D. USEPA interprets section 107(d)(3)(E)(v) to mean that, for a redesignation request to be approved, the State must have met all requirements that became applicable to the subject area prior to or at the time of the submission of the redesignation request.

Vanderburgh County is covered by a State Implementation Plan (SIP) approved under section 110 of the CAA. Indiana has implemented this SIP in Vanderburgh County.

In the case of marginal ozone nonattainment areas, such as Vanderburgh County, the section 172(c)(1) Reasonably Available Control Measures were superseded by section 182(a)(2) Reasonably Available Control Technology (RACT) requirements, which did not require newly-designated marginal ozone nonattainment areas to submit RACT corrections. *See* General Preamble for the Implementation of Title I, 57 FR at 13503, and the Volatile Organic Compound (VOC) RACT fix-up rulemaking published at 58 FR 49458. Thus, no additional RACT submissions were required for Vanderburgh County to be redesignated. Also, by virtue of provisions of section 182(a), marginal areas were not required to submit a demonstration that the SIP provides for attainment.

The section 172(c)(3) base year emissions inventory requirement has been met by the submission and approval of the 1990 base year inventory required under subpart 2 of part D, section 182(a)(1). (50 FR 31544, (June 20, 1994)). Indiana submitted a SIP revision covering regulations requiring the submittal of annual emission statements by facilities with potential VOC emissions equal to or exceeding 25 tons per year. A direct final rulemaking approving this SIP revision was published on June 10, 1994 (59 FR 29953).

As for the section 172(c)(5) New Source Review (NSR) requirement, USEPA has determined that areas being redesignated to attainment need not comply with the NSR requirement prior to redesignation, provided that the area demonstrates maintenance of the standard without part D NSR in effect. A memorandum from Mary D. Nichols, Assistant Administrator for Air and Radiation, dated October 14, 1994, titled ‘‘Part D New Source Review (part D NSR) Requirements for Areas Requesting Redesignation to Attainment,’’ fully describes the rationale for this view, and is based on the Agency’s authority to establish *de minimis* exceptions to statutory requirements. *See Alabama Power Co.* v. *Costle,* 636 F. 2d 323, 360–61 (D.C. Cir. 1979). Once the area is redesignated to attainment, the Prevention of Significant Deterioration (PSD) program, which has been delegated to Indiana, will become effective immediately. Additionally, the USEPA has approved a NSR revision to the Indiana SIP which meets the requirements of part D of the Act. See 59 FR 51108 (October 7, 1994). This NSR SIP revision became effective in December 1994.

(a) Section 176 Conformity Requirements

Section 176(c) of the Act requires States to revise their SIPs to establish criteria and procedures to ensure that, before they are taken, Federal actions conform to the air quality planning goals in the applicable State SIP. The requirement to determine conformity applies to transportation plans, programs and projects developed, funded or approved under Title 23 U.S.C. or the Federal Transit Act (‘‘transportation conformity’’), as well as to all other Federal actions (‘‘general conformity’’). Section 176 further provides that the conformity revisions to be submitted by the States must be consistent with Federal conformity regulations that the Act required the USEPA to promulgate. Congress provided for the State revisions to be submitted one year after the date of promulgation of final USEPA conformity regulations.

The USEPA promulgated final transportation conformity regulations on November 24, 1993 (58 FR 62188) and general conformity regulations on November 30, 1993 (58 FR 63214). These conformity rules require that States adopt both transportation and general conformity provisions in the SIP for areas designated as nonattainment or subject to a maintenance plan approved under section 175A of the Act. Pursuant to 40 CFR 51.396 of the transportation conformity rule and 40 CFR 51.851 of the general conformity rule, the State of Indiana is required to submit a SIP revision containing conformity criteria and procedures consistent with those established in the Federal rule. However, the federal transportation conformity regulations are currently being amended for the third time. Indiana intends to submit transportation conformity regulations when the federal regulations complete rulemaking. Because the redesignation request was submitted before these SIP revisions came due, they are not applicable requirements under section 107(d)(3)(E)(v).

Because areas are subject to the conformity requirements regardless of whether they are redesignated to attainment and must implement conformity under Federal rules if State rules are not yet adopted, the USEPA believes it is reasonable to view these requirements as not being applicable requirements for purposes of evaluating a redesignation request.

For the reasons just discussed, the USEPA believes that the ozone request for Vanderburgh County may be approved notwithstanding the lack of fully approved State transportation and general conformity rules. See also the Tampa, Florida ozone redesignation of December 7, 1995 (60 FR 62748).

(b) Subpart 2 Requirements

Marginal ozone nonattainment areas are subject to the requirements of section 182(a) of subpart 2. Indiana has met all of the applicable requirements of that subsection with respect to the Evansville area. The emissions inventory required by section 182(a)(1) has been approved. (See 59 FR 31544 (June 20, 1994)). The emission statement SIP required by section 182(a)(3)(B) has been approved. (See 59 FR 29953 (June 10, 1994)). As noted above, RACT corrections were not required under section 182(a)(2) for areas such as Vanderburgh County that were not designated nonattainment until after the 1990 CAA Amendments. Similarly, section 182(a)(2) does not require the submission of an Inspection and Maintenance (I/M) SIP revision for Vanderburgh County since the area was not required to have an I/M program before the enactment of the 1990 CAA Amendments. Finally, the State need not comply with the requirements of section 182(a) concerning revisions to the part D NSR program in order for the Vanderburgh County area to be redesignated for the reasons explained above in connection with the discussion of the section 172(c)(5) NSR requirement.

3. The improvement in air quality must be due to permanent and enforceable reductions in emissions resulting from the SIP, federal measures and other permanent and enforceable reductions.

Implementation of VOC emission controls, such as the Federal Motor Vehicle Emission Control Program, and permanent, enforceable emission reductions from source closures have led to VOC emission reductions. A listing of major source VOC emissions for 1988 and 1990 shows that stationary source VOC emissions in Vanderburgh County declined by 339 tons per year (approximately 1.1 tons per day) between 1988 and 1990. Permanent VOC emission reductions due to source closures and implementation of emission controls totaled 570 tons per year in the same period (some of this emission reduction was offset by source growth). Indiana asserts that these point source emission reductions are permanent and enforceable. Indiana further states that it will not renew the permits of closed sources, will require these sources to undergo review under PSD or NSR requirements if they seek to restart, and will prohibit these facilities from banking the pre-closure emissions against future source growth.

4. The area must have a fully approved maintenance plan meeting the requirements of Section 175A.

Section 175A of the CAA sets forth the elements of a maintenance plan for areas seeking redesignation from nonattainment to attainment. The maintenance plan is a SIP revision which provides for maintenance of the relevant NAAQS in the area for at least 10 years after redesignation. A September 4, 1992, USEPA memorandum from the Director of the Air Quality Management Division, Office of Air Quality Planning and Standards, to Directors of Regional Air Divisions regarding redesignation provides further guidance on the required content of a maintenance plan.

An ozone maintenance plan should address the following five areas: the attainment inventory, maintenance demonstration, monitoring network, verification of continued attainment, and a contingency plan. The attainment emissions inventory identifies the emissions level in the area which is sufficient to attain the ozone NAAQS, and includes emissions during the period when the area attained the NAAQS (the first three year period when a violation of the NAAQS was not recorded). Maintenance is demonstrated by showing that future emissions will not exceed the level established by the attainment inventory. Provisions for continued operation of an appropriate air quality monitoring network are to be included in the maintenance plan. The State must show how it will track and verify the progress of the maintenance plan. Finally, the maintenance plan must include contingency measures which ensure prompt correction of any violation of the ozone standard. The Act also requires [section 175(b)] a second SIP revision eight years after an area is redesignated to attainment to assure maintenance of the NAAQS for an additional 10 years beyond the first 10 year maintenance period.

The details of the Evansville maintenance plan are reviewed in the April 26, 1994 TSD, which concludes that the maintenance plan meets all of the applicable requirements. The State commits to continue monitoring of ozone during the 10-year maintenance period. Any changes in the monitoring systems will be subject to USEPA approval.

To help verify maintenance of the standard, the State commits to require stationary sources to annually submit information on their emissions in accordance with the States emission statement rule (326 IAC 2–6). Data from these emission statements and other data sources will be used to determine if emissions have exceeded 1990 base year levels.

Finally, the State has selected a joint set of possible contingency emission control measures and a 2-level approach for triggering of contingency measures. A level I response occurs in the event that the ozone NAAQS is violated. This response entails conducting an analysis to determine the level of control measures needed to assure expeditious future attainment of the ozone NAAQS. Measures that could be implemented quickly would be selected so as to be in place within 12 months after the State is aware of a NAAQS violation. (Note that the State has not preselected specific contingency measures to be implemented in case a level I response is required.) A level II response would be implemented in the event that: (a) The monitored ambient levels of ozone exceed 0.115 ppm more than once in any year at any site in the redesignated area; (b) the level of VOC, Oxides of Nitrogen (NO_X), or Carbon Monoxide (CO), emissions increase above the 1990 (attainment) emissions level; or (c) the level of total VOC emissions for any future year has increased above the level recorded in the prior year sufficiently so that an increase of the same magnitude in the following year could result in a level of emissions exceeding those recorded in 1990 by five percent or more. A level II response would consist of a study to determine whether the noted trends are likely to continue, and if so, to determine control measures necessary to reverse the trends, taking into consideration ease and timing of implementation as well as economic and social considerations. The contingency portion of the maintenance plan for the Evansville area was found to be acceptable. In addition, demonstration of maintenance was successfully made through emission projections through 2006. (Note that the use of 2006 covers a period extending for ten ozone seasons from now and complies with USEPA redesignation policy given the State's November 4, 1993 submittal date for a complete redesignation request and the State's assumption of a two-year period for USEPA's processing of the rulemaking on the redesignation request.) See the April 26, 1994 TSD for a summary of the contingency measures the State has identified.

The emissions summary for VOC and NO_X are provided below for the Vanderburgh County area:

TABLE 1.—VOC EMISSIONS IN TONS PER SUMMER DAY

Year	Point sources	Area sources	Mobile sources	Off-Road mobile	Biogenic	Totals
1990	12.76	12.46	25.25	7.50	8.37	66.34
1995	13.74	12.82	20.77	7.74	8.37	63.44
2000	14.73	13.18	16.29	8.00	8.37	60.57
2006	15.91	13.61	10.91	8.28	8.37	57.08
2007	16.11	13.68	10.01	8.33	8.37	56.50

TABLE 2. NO_X Emissions in Tons Per Summer Day

Year	Point sources	Area sources	Mobile sources	Off-Road mobile	Biogenic	Totals
1990	2.78	2.14	14.11	7.70	n.a.	26.73
1995	2.98	2.27	13.31	7.86	n.a.	26.42
2000	3.18	2.41	12.52	8.02	n.a.	26.13
2006	3.42	2.57	11.56	8.21	n.a.	25.76
2007	3.46	2.60	11.40	8.24	n.a.	25.70

Note that the 2007 emission estimates were derived by the USEPA using source growth rates provided by the State.

The State commits to continuing the operation of the monitors in the area. It will also track the maintenance of the area by regularly updating the emissions inventory for the area.

If the monitored air quality levels exceed the NAAQS, the contingency plan will be triggered. In addition, Indiana is required to submit a revision to the maintenance plan eight years after redesignation to attainment which demonstrates that the NAAQS will be maintained for a second 10 year period.

5. Implementation of All Requirements of Section 110 and Part D of the Act

As indicated above, all requirements of the Act applicable to this area have been met through SIP revision submittals. These SIP revisions have been approved through final rulemaking.

IV. Responses to Comments on the July 8, 1994 Direct Final Rulemaking

Five sets of comments were received concerning the July 8, 1994 direct final rulemaking on the redesignation of Vanderburgh County to attainment of the ozone standard. The summarized comments and USEPA's responses are presented below:

Comment: A commenter objects to redesignating Vanderburgh County to attainment because of Vanderburgh County's lack of past performance in dealing with the area's ozone problem. In support of this position, the commenter submitted several newspaper articles and an organization publication noting the lack of such action on the part of Vanderburgh County/Evansville officials. The commenter is concerned that designating Vanderburgh County to attainment of the ozone NAAQS will only exacerbate an already existing problem.

Response: During the years of 1990 through 1993, quality assured ozone monitoring data were collected at six sites in Indiana and at two sites in Kentucky within or in the proximity of the Evansville nonattainment area. No violations of the ozone standard were monitored during this period. Therefore, the area's ozone levels have shown improvement over the 1987–1989 ozone standard violation levels, which were the basis for the nonattainment designation for Vanderburgh County. At the time of the redesignation request, sufficient ''clean'' air quality data existed to support the redesignation request. Air quality data through 1996 from monitors within the Vanderburgh County nonattainment area continue to show attainment of the ozone standard.

Vanderburgh County is currently a marginal ozone nonattainment area. The Act provides only minimal ozone precursor reduction requirements (the correction of deficient rules and 1.1 for 1 offsets for major new sources) for such an area. Since emission control rules, such as RACT for stationary sources, were not previously required and are not currently required for the Evansville area, leaving the nonattainment designation in place for the area would not result in significant new emission reduction requirements for this area.

Reductions in emissions have been gained through vehicle per mile emission rate decreases through the implementation of the Federal Motor Vehicle Emission Control Program (these emission rate decreases are offset in part by increases in vehicle miles traveled). In addition, permanent source closures have occurred in the area as noted in the State's demonstration of maintenance. The USEPA believes these emission reductions will tend to result in improved air quality.

Comment: A commenter objects to the redesignation because the commenter believes ozone levels in the vicinity of the Evansville area are higher than those reported for Vanderburgh County. The commenter, referencing several newspaper articles, believes that ozone levels are not measured in the areas of highest ozone concentrations.

Response: The USEPA has reviewed ozone data for the Vanderburgh County nonattainment area, as well as data from outside the nonattainment area in evaluating the redesignation request. The ozone concentrations being reported to the public in the newspaper articles referenced by the commenter were only from Vanderburgh County monitors and did not include data from adjoining counties, outside of the nonattainment area. Ozone is also monitored at three sites in adjoining Warrick County. It is noted that higher peak ozone concentrations may be found in Warrick County. The extent, however, of the impact of emissions from Vanderburgh County on ozone concentrations in Warrick County is unclear.

Ozone, at relatively high concentrations, and its precursors, most notably VOC and NOx, can be transported over considerable distances downwind of a precursor source area. Maximum ozone levels are generally found 15 to 30 (or more) miles downwind of the sources of ozone precursors. Given this, IDEM considered the 1990 through 1993 ozone data from Vanderburgh County and counties surrounding Vanderburgh County in the redesignation request submitted on November 4, 1993. These data showed no violation of the ozone NAAQS prior to the 1994 ozone season. The USEPA considers the area covered in IDEM's data analysis to be adequate.

Comment: A commenter objects to the redesignation of Vanderburgh County for two reasons. The first reason is the low use of Evansville buses. The commenter believes that improving the quality of the Evansville bus service will increase ridership and contribute to improving air quality. The second reason is based on the commenter's concerns about the chemicals being emitted by industries in the Evansville area. The commenter is concerned that some emissions are toxins and carcinogens and that this problem should be addressed before the area is redesignated to attainment of the ozone standard.

Response: The USEPA agrees with the commenter that improved bus service and increased citizen usage of buses would help to reduce the emission of ozone precursors. USEPA encourages improvements in bus service and greater usage to reduce pollutant emissions. Such actions, however, cannot be mandated by the USEPA. State and local agencies are generally free to choose the mixtures of transportation control measures used to control pollutant emissions. In addition, since the Evansville area is classified as marginal nonattainment for ozone, the Act does not require such emission controls.

While the USEPA shares the commenter's concerns over chemicals emitted by industries (some of the VOC which act as ozone precursors are possible toxins and carcinogens), control of air toxins and carcinogens is addressed under separate provisions of the Act (section 112) and is expected to result in a decline in these emissions in the future. The designation of an area as attainment or nonattainment for ozone is only for the purpose of controlling ozone. For redesignation purposes, USEPA evaluates, among other factors, whether the State has met all applicable requirements for the area under Title I, section 110 (State Implementation Plans) and part D (nonattainment plan provisions under section 172(c)). USEPA has determined that the State has met these requirements. While the control of air toxins is the subject of section 112 of the Act, not the SIP program, the USEPA encourages States to take VOC and toxins/carcinogens into account when selecting control measures to help assure maximum environmental benefits from emission control measures. The USEPA, however, cannot compel such actions under the Act for the purposes of controlling ozone levels.

Comment: Commenters argue that the redesignation of Vanderburgh County to attainment is disapprovable on the following bases:

1. The State, at the time of the redesignation request submittal, had failed to correct the State's part D New Source Review (NSR) regulations. The State has failed to meet the Act's requirement that the SIP must comply with Act and be fully approved at the time the redesignation request is submitted;

2. The State has failed to demonstrate that the air quality improvements in the Evansville area are due to permanent and enforceable emission reductions. The commenters argue that a September 4, 1992 USEPA redesignation policy guidance is clear in requiring analysis of whether the improved air quality has resulted in part from either unique meteorological conditions or temporary changes in economic conditions. Air quality improvements due to these air quality impacts are not permanent, and, therefore, are not creditable;

3. The State has failed to fully predict the impacts of future transportation projects on growth in vehicle miles traveled and on mobile source emissions; and

4. The USEPA has failed to consider the impacts on downwind ozone transport caused by the redesignation and the associated loss of emission control requirements.

Response: The following presents USEPA's responses to each of the comments above in the order given:

1. USEPA believes that nonattainment areas can be redesignated to attainment of the ozone standard notwithstanding the lack of a fully approved NSR program meeting the requirements of the Act and the absence of such an NSR program from the contingency plan. USEPA believes that not requiring a fully approved NSR program as a prerequisite to the submittal of the State's request for redesignation is justifiable as an exercise of the USEPA's general authority to establish *de minimis* exceptions to statutory requirements. See *Alabama Power Co.* v. *Costle,* 636 F.2d 323, 360–61 (D.C. Cir. 1979). A memorandum from Mary D. Nichols, Assistant Administrator for Air and Radiation, dated October 14, 1994, titled ''Part D New Source Review (part D NSR) Requirements for Areas Requesting Redesignation to Attainment,'' fully describes the rationale for this view, and is based on the Agency's authority to establish *de minimis* exceptions to statutory requirements. Once the area is redesignated to attainment, the PSD program, which has been delegated to Indiana, will become effective immediately. Additionally, it is noted that the USEPA has approved a NSR revision to the Indiana SIP which meets the requirements of part D of the Act. See 59 FR 51108 (October 7, 1994). This NSR SIP revision became effective in December 1994.

2. The September 4, 1992 USEPA policy guidance referred to by the commenter states that ''attainment resulting from temporary reduction in emission rates (e.g., reduced production or shutdowns due to temporary adverse economic conditions) or unusually favorable meteorology would not qualify as an air quality improvement due to permanent and enforceable emission reductions.'' Neither the State nor the USEPA has neglected these issues in preparing and analyzing Indiana's redesignation request. Rather, the USEPA believes that the State has adequately demonstrated that the improvement in air quality was not due to temporary economic downturn or unusually favorable meteorology.

With respect to the issue of temporary emission reductions due to economic downturn, the USEPA noted in this rulemaking and the July 8, 1994 direct final rulemaking (59 FR 35048) that the State has shown that attainment of the ozone standard is attributable to permanent and enforceable emission reductions. These emission reductions have resulted from permanent source closures and implementation of the Federal Motor Vehicle Emission Control Program. These emission reductions are permanent and enforceable. In the case of source closures, the source permits associated with these sources have been terminated and will not be reissued. Reopening of these sources would involve subjecting these sources to new source review requirements. It is USEPA's judgment that these emission reductions have contributed to the air quality improvement observed prior to the redesignation request submittal.

With respect to the issue of unusual meteorology, the State has compared the average meteorological parameters of maximum daily temperature, daily mean wind speed, percent of possible sunshine, and relative humidity for the periods of May through August, 1990 through 1992, with the 30-year (1961–1990) averages for these parameters. The 1990–1992 averages were found to be equivalent to the 30-year averages with only minor differences. Based on a comparison of these average parameters, it was concluded that the 1990–1992 period was not atypically non-conducive to ozone formation.

3. The USEPA conformity rule (58 FR 62218) requires the States to conduct conformity analyses for both nonattainment areas and attainment areas subject to maintenance plans. The State of Indiana is preparing its conformity rule to comply with USEPA's conformity rule. Therefore, any major federally funded and State funded projects in the redesignated area would be addressed through State conformity analyses and would be subject to the emissions budget established by the maintenance plan. Minor changes in the public transportation system would not be subject to the conformity analyses. The State's predictions of future year emissions did assume growth in mobile source activity. Moreover, the review required by the maintenance plan if ozone levels over 115 ppb are monitored gives the State the opportunity to adjust those predictions in light of transportation projects that were not known at the time of submission of the maintenance plan.

4. As discussed above, in accord with section 107(d)(1)(A), the USEPA is

considering information regarding the extent of the contribution of sources in Vanderburgh County to its downwind environs and is requesting comment on that issue in this notice. The USEPA notes, however, that this redesignation would not result in an increase in emissions from Vanderburgh County. Existing emission controls will not be dropped or relaxed as a consequence of the redesignation. Indeed, the maintenance demonstration projects stable or declining emissions from Vanderburgh County sources during the 10-year maintenance period, which means that any emission reduction contribution from Vanderburgh County sources would not be expected to decline after redesignation. Furthermore, as Vanderburgh County itself is attaining the ozone NAAQS, even if it remained designated nonattainment, under section 181(b)(2) of the Act, it would not be ''bumped-up'' to a moderate classification, and no new emission controls would be required to be adopted. Thus, additional emission controls would not be required as a consequence of a disapproval of the Vanderburgh County redesignation. The USEPA further notes that, if it concludes, on the basis of the OTAG modeling results or otherwise, that additional controls are needed in upwind areas to reduce transported emissions having effects on other states, a SIP-call to require such measures would be based on section 110(a)(2)(D) of the Act and could apply to areas regardless of whether they are designated attainment or nonattainment of the ozone NAAQS. Therefore, the redesignation of Vanderburgh County to attainment for ozone will not preclude the USEPA from obtaining emission reductions if needed to prevent excessive ozone transport from this area to other states.

V. IDEM Technical Support Document

Additional comments were submitted by IDEM during the comment period for the direct final rulemaking. These comments were primarily directed to the unusual nature of the 1994 ozone standard violation recorded in Warrick County. The validity of this ozone standard violation and its impacts on Indiana's redesignation request are discussed in the TSD for this proposed rulemaking. The State's comments submitted during the public comment period are addressed through that discussion.

VI. Public Comments Subsequent to the 1994 Ozone Standard Violation in Warrick County, Indiana

Subsequent to the 1994 ozone standard violation discussed above, a number of public comments were received by the USEPA regarding the redesignation of Vanderburgh County to attainment of the ozone standard. These comments can be divided into two main subgroups. The first subgroup of comments from United States Congressmen, the State of Indiana, Evansville and Vanderburgh County local agency representatives, and business and industrial representatives favor the redesignation of Vanderburgh County to attainment. Many of these commenters are concerned about the possible economic impacts of Vanderburgh County remaining a nonattainment area. These commenters raised the following general comments in support of the redesignation:

Comment: Many commenters support IDEM's analysis of the 1994 ozone data and the IDEM conclusion that the Alcoa data may reflect a positive bias during the April 22 through June, 1994 period.

Response: IDEM's review of the 1994 ozone data is discussed in detail above. The USEPA's conclusions regarding this analysis and the validity of its conclusions are contained in the Background and Conclusion section of the TSD for this rulemaking.

Comment: Some commenters have noted that the Warrick County ozone standard violation, having occurred outside of Vanderburgh County, should not be used to disapprove the redesignation of Vanderburgh County.

Response: The USEPA believes that a thorough review of all data is necessary before taking final action on the State's request. Among other factors, the Evansville nonattainment area is attaining the ozone standard based on quality assured data from monitors located within Vanderburgh County. On the other hand, even though the Alcoa monitor is located outside the Evansville nonattainment area, the USEPA also considered the data from this monitor in reviewing and evaluating the State's request.

As explained above, on the basis of both section 107(d)(1) of the Act and USEPA's written redesignation policy (September 4, 1992 memorandum titled ''Procedures for Processing Requests to Redesignate Areas to Attainment'' from John Calcagni to Air Division Directors), ozone data from all ozone monitors in an area and its downwind environs are to be considered when reviewing a redesignation request. This means that ozone data from Warrick County and other counties surrounding Vanderburgh County must be considered when reviewing the redesignation request for Vanderburgh County. Of course, these analyses must also consider wind directions leading to high ozone levels in these outlying areas. The temporal and meteorological aspects of ozone formation typically produce peak ozone concentrations 15 to 30 miles downwind (or farther for large source areas) of the ozone precursor source area. This means that peak ozone concentrations can be produced outside of a single county source/nonattainment area. Since Warrick County is downwind of Vanderburgh County on some high ozone days, the USEPA is technically justified in considering ozone data from this County when evaluating the attainment status of Vanderburgh County.

Comment: Many commenters note that IDEM has developed a viable maintenance plan to deal with emission increases above the 1990 emission total (the attainment emissions level) and to deal with future violations of the ozone standard.

Response: USEPA concurs with this comment as reflected in the April 26, 1994 TSD and believes that the State's maintenance plan shows continued attainment of the standard through the year 2006. (USEPA has projected continued attainment through 2007 using source growth rates provided by the State. Although the State, in compliance with USEPA maintenance demonstration policy, projects continued attainment through 2006, the timing of rulemaking on this issue led the USEPA to consider projection of emissions through 2007.) Permanent and enforceable controls such as the Federal motor vehicle control program are in place and should ensure that emissions will not exceed the level of the 1990 attainment base year during the 10-year maintenance period. Furthermore, the maintenance plan contains contingency measures in the event of a violation of the ozone NAAQS.

The maintenance plan has not accounted for the emissions increases resulting from traffic growth associated with the operation of a proposed floating casino in the area or with traffic that will be drawn to the new Toyota truck plant planned for Gibson County, which adjoins Vanderburgh County to the north. The State and USEPA currently lack data to assess the impacts of these traffic impacts. Consequently, the USEPA is proposing approval at this time. The USEPA also notes that the maintenance plan provides additional protection against unanticipated emission increases as it contains triggers for assessment of the need for additional emission controls if the emissions are subsequently projected to increase above the 1990 base year emissions level. Through this process, previously unanticipated emission increases could trigger the need for additional emission controls. It should also be noted that if the emission increases resulting from the traffic growth of concern here cause a future violation of the ozone NAAQS, the maintenance plan will obligate the State to select additional emission control measures to eliminate the air quality problem. In addition, the State will revise the maintenance plan within eight years and can include the additional emissions resulting from the traffic growth at that time.

Comment: Commenters in favor of the redesignation claim that Vanderburgh County has been singled out for nonattainment status even though emissions from Posey and Warrick Counties, Indiana and Henderson and Daviess Counties, Kentucky may have also contributed to the ozone standard violation at the Alcoa site and the elevated ozone levels at the other monitoring sites in the Evansville area.

Response: The USEPA does not believe that Vanderburgh County is being singled out. It was initially designated as nonattainment in 1991 as a consequence of an ozone standard violation within its boundaries, and the USEPA is now proposing to redesignate it to attainment. The USEPA has evaluated the available information concerning the meteorology and the sources of the emissions that led to the ozone standard violation in Warrick County, and is requesting comment on issues regarding the effect of the contribution of Vanderburgh County emissions to that violation. The meteorological data indicate that emissions from other areas may have contributed to the exceedances monitored in Warrick County.

Comment: Several commenters assert that never before has one single monitor been used to override the evidence of all remaining monitors in a region. The commenters believe the evidence in favor of redesignating Vanderburgh County to attainment is overwhelming and that the USEPA should not base a decision with such economic impact on questionable information when all other information points toward attainment of the ozone standard.

Response: When an area's attainment status is determined, each monitor in the area is judged independently. Ozone is not directly emitted into the atmosphere, but results from complex photochemical reactions involving organic compounds, oxides of nitrogen and solar radiation. The relationships between primary emissions and ozone formation tend to produce large separations spatially and temporally between the major precursor emission sources and the areas of high ozone pollution. This suggests that the meteorological transport process and relationships between sources and sinks (reactions with airborn chemicals or reactions with surfaces that locally reduce ozone levels) need to be considered in the placement of monitoring stations and in the evaluation of the monitoring data.

USEPA's redesignation policy requires attainment of the ozone standard at *all* ozone monitors in an area seeking redesignation to attainment. Each monitor in an area is judged independently because ozone formation, transport, and sinks can lead to spatial differences in monitoring results. Nonetheless, monitoring results at a given site can represent the impact of emissions from a large upwind source area. In addition, each monitor represents a geographic region within a community. Therefore, USEPA believes it is appropriate and necessary for each monitor in the area to meet the standard to ensure people in these areas are not being exposed to levels above the standard. Because of distribution of sources within an area, the nature of ozone formation and the effects of meteorology, it is not expected that all monitors will show equivalent readings. Within a nonattainment area, if any one monitor shows a violation of the standard, the area is considered to be in nonattainment of the standard. The USEPA has always considered ozone on a per monitor basis, refusing to redesignate an area to attainment if the ozone standard is violated at any monitoring site in the nonattainment area. Monitors outside of the nonattainment area are evaluated for impacts from the area under consideration. The CAA in section 107(d)(1)(A)(i), as noted above, defines nonattainment as ''any area that does not meet (or contributes to ambient air quality in a nearby area that does not meet) the national primary or secondary ambient air quality standard for the pollutant, * * *''.

The USEPA promulgated federal monitoring regulations that established minimum monitor requirements and criteria for uniform monitor siting and quality assurance procedures (40 CFR part 58). Only data meeting these siting and quality control requirements are used in regulatory decisions. The valid, quality assured violation of the ozone standard recorded in Warrick County thus must be considered by the USEPA when considering the redesignation of Vanderburgh County.

Comment: Several commenters believe that the Alcoa monitoring site, as a special purpose/prevention of significant deterioration monitor site, has not ever been part of Evansville's ambient monitoring system, and, therefore, data from this site should not be considered when reviewing the designation of Vanderburgh County.

Response: The IDEM has never formally identified the monitors belonging in the monitoring network for each nonattainment area. In IDEM's March 15, 1991, submittal to support the State's proposal for the classification and designation of Vanderburgh County as marginal nonattainment for ozone and to exclude surrounding counties from this designation, IDEM included ozone data from the Alcoa site as part of the monitoring system used to judge the attainment status of Vanderburgh County and to justify the exclusion of Warrick County from the nonattainment area. The CAA requires nonattainment areas with moderate and above classifications to include the entire MSA to assure that the entire source area is included in the nonattainment area. In the case of marginal ozone nonattainment areas, such as the Evansville area, the CAA gives the States and USEPA discretion in determining the size of the nonattainment area. In 1991, the USEPA accepted IDEM's recommendation to restrict the nonattainment area to only Vanderburgh County.

The Alcoa monitor has historically been used to make decisions about the Evansville area. There is, however, no ''official'' monitoring system declared by Indiana for the Evansville area. The USEPA has in the past considered data from PSD monitors when making designation decisions as long as the data met the quality assurance standards for ambient air networks. The quality assurance tests conducted on the Alcoa monitor were all well within the required limits. All data in the AIRS data system have been quality assured by the State air agencies as having met the requirements for valid data to be used in the decision-making process.

Comment: A commenter notes that, on two of the exceedance days at the Alcoa site, winds were from the east placing this site upwind of the Evansville area not downwind of it.

Response: The USEPA agrees with the commenter. It is apparent from the meteorological data that emissions from areas other than Vanderburgh County may have contributed to the 1994 ozone standard violation at the Alcoa site. Emissions from other areas also appear to have contributed to the ozone standard exceedances on the days on which the Alcoa site was downwind of Vanderburgh County (the IDEM has noted relatively high background ozone concentrations on these days), as well as on the other two exceedance days.

Comment: Commenters note that Evansville industries have spent millions of dollars to reduce emissions, particularly emissions of VOC, NOx, and chloroflourocarbons to improve air quality and protect the environment. They believe the redesignation of Vanderburgh County to attainment would recognize this effort and encourage further progress.

Response: It is acknowledged that the Evansville industries have implemented emission controls to comply with various requirements of the Clean Air Act. Some of these controls probably have contributed to lower VOC emissions (the controls mentioned by the commenter, however, were implemented to reduce chlorofluorocarbon emissions, which are nonreactive and have little or no impacts on ground level ozone concentrations). To this extent, these facilities are recognized for contributing to lower ozone concentrations. Without these controls, the ozone levels could have been even higher in 1994. It should be noted that industries in Vanderburgh County are not required to have VOC RACT emission controls because Vanderburgh County was attainment prior to the enactment of the 1990 CAA.

Comment: A commenter, noting the recent public discussions of the Evansville redesignation and the possible inadequacy of the current ozone standard to protect public health, questions the ability of the area to attain a tighter standard. This commenter also questions the assertions of local physicians blaming ozone levels for triggering many asthma attacks during the summer months. The commenter believes the physicians should consider the fact that Evansville area is located amidst an agricultural area and that the resulting particulates and pollen along with ozone, heat, and humidity may play a role in these asthma attacks at this time of the year.

Response: The standard against which Evansville's attainment is judged is the current 0.12 parts per million ozone standard. The USEPA is not basing its decision on a possible, future tighter ozone standard, and the ability or inability of the Evansville area to attain a tighter standard is not an issue in this proposal.

With regard to impacts of other factors in causing respiratory problems, it is agreed that such factors may have caused some of the respiratory problems observed in the area. It is noted that many health studies have confirmed the negative health impacts that ozone has on the respiratory system. These studies were the basis of the current ozone standard. Recent health studies further elaborate on these impacts and are the subject of USEPA's current proposal to revise the ozone standard. See 61 FR 65716, December 13, 1996. The connection between ozone and asthma attacks is discussed in that proposal and is not further discussed here.

Comment: A commenter believes the siting of the Alcoa monitor is incorrect since this site may be impacted by particulate emissions from the Alcoa plant and the local coal-fired power plant and by ozone generated locally by high power lines carrying electricity from the power plant and to the Alcoa plant.

Response: As noted in the June 5, 1995 TSD submitted by IDEM, IDEM did consider the factors mentioned by the commenter. These factors were ruled out as significant contributors to the high ozone levels monitored at the Alcoa site. The USEPA agrees with IDEM's analysis.

Comment: A commenter questions the quality assurance of the Alcoa monitor. This commenter also wants to know why, if the Alcoa monitor was part of the monitoring system used to evaluate Evansville air quality, were no industrial representatives or the public previously aware of its existence?

Response: Review of the quality assurance records in AIRS and the June 5, 1995 IDEM TSD show that Alcoa and the State actively participated in the quality assurance of the Alcoa monitor. Quality assurance records show that the monitor was performing well within acceptable quality assurance limits during the period with the 1994 ozone standard violation. This monitor recorded ozone concentrations with very small error levels (small percentage differences from calibration and precision check ozone input levels) during this period. In addition, the State has quality assured Alcoa's ozone calibrator unit, removing this as a significant source of ozone concentration errors.

As evidenced in the March 15, 1991 ozone designation/classification submittal, IDEM has been aware of the Alcoa ozone monitor for some time. In fact, IDEM has supplied Alcoa ozone data for inclusion in AIRS since 1988. The AIRS data are available to the public.

Comment: A commenter is concerned that retaining the marginal nonattainment status for Vanderburgh County will ultimately result in its being bumped up to moderate nonattainment with serious economic consequences. The commenter believes that local environmental groups are not aware of this possibility nor thoroughly understand the consequences of such an action.

Response: The USEPA evaluated the attainment status of Vanderburgh County at the end of 1993 as required by the CAA. Monitors in Vanderburgh County were indicating attainment of the ozone standard in 1993 and continue to record attainment of the ozone standard. As noted above, this fact provides a basis for not bumping up Vanderburgh County to the classification of moderate nonattainment.

The local environmental groups are aware of the impacts of a bump-up of the area to moderate nonattainment. As evidenced by the comments addressed elsewhere in this proposed rulemaking, some environmental groups have requested such a bump-up of the area.

Comment: A commenter asserts that local environmental groups err in believing that the Evansville ozone problem is primarily due to industrial emissions. The environmental groups fail to recognize that 38 percent of the VOC emissions originate from mobile sources and that 19 percent of the emissions come from area sources. With the future emission controls required under other portions of the Clean Air Act, such as Maximum Available Control Technology (MACT) for sources of toxic emissions and New Source Performance Standards (NSPS), the relative emissions contributions from industrial sources will decline. This means that control of other sources should be considered.

Response: The commenter is correct that sources other than industrial sources may also share in contributing to the 1994 ozone standard violation. As evidenced in IDEM's 1990 base year inventory for Vanderburgh County (the source of the emission percentages expressed by the commenter), many sources contribute to this problem. It is reasonable to request that control of these emissions be considered along with the control of emissions from industrial sources.

Comment: A commenter states that USEPA should not revise the ozone standard as recommended by the environmental groups in the Evansville area. The commenter believes that tightening of the standard would make it very difficult for the area to achieve the goals of the State's maintenance plan. The commenter recommends that the 0.12 parts per million ozone standard remain in effect.

Response: The revision of the ozone standard is not an issue in this action. In this action, USEPA is solely concerned with the attainment and maintenance of the current ozone standard.

The second subgroup of comments was submitted by environmental groups and residents of the Evansville metropolitan area. These comments generally recommend disapproval of the redesignation of Vanderburgh County to attainment or criticize the USEPA for not following appropriate procedures in rulemaking and making decisions on this issue. These comments are summarized below:

Comment: Commenters object to USEPA's October 11, 1995 decision to redesignate Vanderburgh County to attainment based on the following facts/ points:

a. The Alcoa ozone standard violation has been quality assured by the State of Indiana as being valid;

b. The Alcoa monitor has been and continues to be part of the Evansville area monitoring system;

c. Redesignating Vanderburgh County in light of the 1994 ozone standard violation violates USEPA's own guidelines;

d. No public hearing in Vanderburgh County was held to address the impacts of the 1994 ozone standard violation; and,

e. Negative health impacts from ozone can occur at levels well below the current standard.

Response: The overall responses to these comments are reflected in this entire proposed rulemaking. The following responses, however, are made to respond to the commenter's specific points:

a. USEPA and IDEM agree that the data establishing the Alcoa ozone standard violation have been quality assured and are valid. IDEM, however, believes that a significant monitor bias can exist even when the monitor is producing quality assured results. IDEM's assertion of monitor bias is supported by the daily maximum ozone concentrations at the Alcoa site as compared to those for the other monitors in the area for the April-June, 1994 period and review of similar data for other periods.

The USEPA has determined that the Alcoa data are valid and quality assured. The quality assurance data demonstrate that the monitor was performing correctly. The source of the high ozone concentrations measured at the Alcoa site is unclear. Source areas outside of Vanderburgh County appear to be contributing to the high ozone concentrations observed at the Alcoa site.

b. As noted above, the IDEM has never formally identified the monitors belonging in the monitoring network for each nonattainment area. In IDEM's March 15, 1991, submittal to support the State's proposal for the classification and designation of Vanderburgh County as marginal nonattainment for ozone and to exclude surrounding counties from this designation, IDEM included ozone data from the Alcoa site as part of the monitoring system used to judge the attainment status of Vanderburgh County and to justify the exclusion of Warrick County from the nonattainment area.

As noted above, the Alcoa monitor has historically been considered when making decisions about the Evansville area. There is, however, no ''official'' monitoring system declared by Indiana for the Evansville area. It should be noted that an IDEM monitor at the Alcoa site has replaced the Alcoa monitor.

c. As explained earlier in this notice, consistent with its existing guidance, the USEPA has evaluated the 1994 exceedances monitored at the Alcoa site and the information available concerning the sources of the emissions resulting in those exceedances. The USEPA believes that this proposal is consistent with USEPA's existing guidance regarding redesignations and the consideration of downwind monitored ozone concentrations. As stated earlier, the USEPA is requesting comment on this issue.

d. The comment is correct. It should be noted that the USEPA is reopening the comment period for the rulemaking on this redesignation and allowing an extended 60 day comment period.

e. On December 13, 1996, the USEPA proposed to revise the current ozone standard (61 FR 65716). The health effects of ozone concentrations below the current ozone standard are an issue being addressed in that rulemaking proceeding and are beyond the scope of this action, which is limited to whether or not the current ozone standard has been attained in Vanderburgh County.

Comment: A number of commenters have requested the reopening of a public review, including public hearings and a public comment period, of the redesignation request, USEPA's decision on this issue, and the implications of the 1994 ozone standard violation. Some commenters have recommended that this issue be the subject of judicial review.

Response: The USEPA will reopen the public comment period on this issue. The 1994 ozone standard violation, June 5, 1995 IDEM technical analysis submittal, and December 7, 1995 IDEM supplemental data all add significant new information to the data and information discussed in the July 8, 1994 USEPA rulemaking. On this basis and given the public interest in this issue, it is appropriate for the USEPA to repropose the rulemaking and to reopen the public comment period for this rulemaking.

Comment: Commenters question the validity of the maintenance demonstration submitted with the redesignation request and the prospects for continued maintenance of the ozone standard. These commenters point out the initiation of river boat gambling in Evansville will draw in excess of 2 million additional cars or vehicle trips to the area per year. It is assumed that this growth in vehicle emissions was not factored into the State's maintenance plan.

Response: The maintenance plan submitted by IDEM was complete and approvable at the time it was submitted on November 4, 1993. A public hearing on the maintenance plan was held by IDEM on August 24, 1993, in Evansville, Indiana. There was one person who commented on the maintenance plan and expressed concerns about a lack of sanctions in the plan should it not be properly implemented. IDEM's response was that, if the State fails to implement the plan, the USEPA may impose sanctions allowed under the CAA, such as withholding federal highway funds.

The maintenance plan does take into account a measure of growth in mobile source emissions. To the extent that the maintenance plan does not include traffic growth due to the casino river boat and to the new Toyota truck plant in Gibson County, it may need to be reviewed when data on the traffic growths become available to determine the effect of these developments on the maintenance plan predictions. As noted elsewhere in this proposed action, this will be the case if the emission increases cause the Vanderburgh County VOC or NOx emissions to increase above attainment year base levels. Also, the transportation conformity process should prevent growth in mobile source emissions from exceeding the ''budget'' in an approved maintenance plan.

The maintenance plan also has a margin of safety to allow for future growth in mobile sources as well as other sources. The Evansville maintenance plan has an extra 9 tons per day of VOC safety margin in 2006 and in 2007, and 1 ton per day NO_X

safety margin in 2006 and in 2007. It should also be noted that the maintenance plan does contain a trigger requiring extra analyses based on VOC emissions exceeding the 1990 base year level. In addition, the requirements for additional emission controls would be triggered should the increased VOC emissions cause a future violation of the ozone NAAQS. In the event of a future ozone standard violation, contingency measures would be invoked to correct the violation and bring the area back into attainment.

Comment: One commenter stated that preparation of the USEPA TSD after the October 11, 1995 USEPA decision to redesignate Vanderburgh County is, at best, superfluous, and, at worse, a direct disregard of the rules and laws under which USEPA is supposed to operate.

Response: The October 11, 1995, letter referred to by the commenter did not serve to redesignate Vanderburgh County; this can only be done through a rulemaking action such as this, with opportunity for public comment. It should also be recognized that the October 11, 1995 letter was not developed without considerable review of the available data by IDEM (as evidenced by IDEM's June 5, 1995 technical support document) and USEPA (USEPA had already given considerable thought to this issue in preparing to respond to comments on the July 8, 1994 direct final rulemaking). Many hours were spent before October 11, 1995, by both agencies reviewing the data and drawing initial conclusions regarding the merits of the 1994 ozone standard violation at the Alcoa site as well as other issues raised by the public. It should also be recognized that the USEPA believed it was appropriate to move ahead with rulemaking to redesignate Vanderburgh County to attainment despite the violation of the ozone standard at the Alcoa site in Warrick County. As noted in the October 11, 1995 letter, this decision was based in part on a commitment by the IDEM to implement its maintenance plan. USEPA is relying on this commitment to implement one or more measures contained in the maintenance plan and others that are as needed to address any ozone air quality problem in the Evansville MSA. Finally, as noted elsewhere in this proposed rulemaking, the USEPA is taking public comments for another 60 days from the date of this proposed action before making a final decision on redesignation request. Submitted comments will be addressed in a future final rulemaking action. Obviously, the October 11, 1995 letter does not represent a final conclusion on this issue.

Comment: Some commenters recommend, based on 1994 and 1995 data, that Vanderburgh County remain designated as nonattainment for the ozone standard and bumped up to a classification of moderate.

Response: When the USEPA evaluated marginal areas for attainment status at the end of 1993, Vanderburgh County and surrounding areas were demonstrating attainment of the ozone standard. The 1994 and 1995 data for monitors in Vanderburgh County continue to show attainment of the standard. Consequently, bump up of Vanderburgh County to a classification of moderate is not justified.

Comment: A commenter notes that the Alcoa monitor recorded 14 hours of ozone standard exceedances in 1994 and that additional exceedances of the standard were recorded in Boonville in 1995.

Response: USEPA's TSD for this proposed rulemaking thoroughly discusses the ozone standard exceedances at the Alcoa monitor. With regard to the 1995 ozone standard exceedance at the Boonville site, it must be noted that this site has not recorded a violation of the ozone standard given the small number of exceedances recorded at this site in the last three years of data collection; the site has recorded less than one ozone standard exceedance per year during the last three years.

Comment: A commenter objects to the fact that IDEM's June 5, 1995 TSD was never subjected to a public review or a public hearing. IDEM's TSD is viewed as being seriously flawed as to its application of science. IDEM's conclusions in the TSD conflict with the conclusion (in the June 5, 1995 TSD and elsewhere) that the Alcoa data are quality assured. The commenter finds IDEM's conclusion of ''unexplained monitor bias'' to be scientifically unfounded.

Response: As noted above and below, USEPA agrees that the June 5, 1995 IDEM technical analysis and other related data should be subjected to public review. This is part of the basis for USEPA reproposing rulemaking on this action and reopening the public comment period on this issue.

Comment: A commenter notes that USEPA's monitoring staff have indicated through internal USEPA memoranda that, as indicated by AIRS data, if there was monitor bias, it is more important to note that significant negative monitor biases are indicated for the Boonville, Tecumseh High School, and Scott School monitors during the April 20 through June, 1994 period. The commenter interprets USEPA memoranda as indicating that these monitors may have been subject to -11 percent biases. The commenters note that this level of bias was sufficient to explain the concentration differences between the Alcoa monitored ozone concentrations and the ozone concentrations monitored at the other ''downwind'' monitoring sites. In addition, the commenter notes that increasing ozone levels by 11 percent at the negatively biased monitors would add 2 days of ozone standard exceedance to the Boonville site (three exceedances in two years considering the 0.131 parts per million exceedance in 1995 at this site) and 1 day of ozone standard exceedance to the Tecumseh High School site.

Response: The August 18, 1995 USEPA memorandum referred to by the commenter presents the annual precision upper and lower 95 percent confidence limits for the four sites operated by Indiana in the Evansville area. These data present ranges of precision data, but by no means imply that the monitors were operating with specific biases during the May through June, 1994 episodes. Although the data imply, for example, that the Boonville monitor tested lower than the actual test concentration, the data do not imply that the Boonville monitor operated at a -11 percent bias. The precision estimates for the Boonville monitor implied only a -1.2 to -3.6 percent difference between the actual concentration and the monitored concentration. The small size of the precision and audit data set led to the relatively large negative precision estimate at the lower end of the 95 percent confidence limit. The precision data do not indicate that the differences in ozone concentrations between the Alcoa and Boonville monitors during the April 22 through June, 1994 period can be simply or entirely explained on the basis of differences in quality assurance for the two monitors.

It should also be noted that the use of the precision data in a manner as used by the commenter to draw conclusions regarding derived non-biased ozone concentrations is technically unacceptable. If the ozone monitors meet quality assurance limits, as all monitoring data included in AIRS have, it is inappropriate to modify the ozone concentrations based on precision data.

Comment: Commenters note that Vanderburgh County has been designated as nonattainment for ozone for a number of years and that the USEPA, State, and local agencies have done little or nothing to correct this problem. One commenter believes that the State's and local agency's attempts to deal with the ozone problems through an Ozone Action Days program are inconsequential. Therefore, the commenters believe that the area does not deserve a redesignation to attainment of the ozone standard and that a redesignation to attainment will assure that no effective actions are taken.

Response: Initially, it should be noted that although Vanderburgh County has been designated as nonattainment, it has in fact been attaining the ozone standard since 1990 because no monitors in Vanderburgh County have recorded a violation of the ozone standard during that time period. Furthermore, it is incorrect to conclude that no emission reductions have been implemented in the Evansville area. Through the Federal Motor Vehicle Emission Control Program, the USEPA has brought about reductions in vehicle per mile emission rates. The Vanderburgh County maintenance plan estimates a 14% reduction in VOCs during the 1990 to 2006 time period because of cleaner automobiles. The maintenance plan in conjunction with other Act requirements, such as conformity, should prevent these reductions from being negated by increases in vehicle miles of travel and other emission increases. The State has adopted the general and transportation conformity rules, and submitted these rules to the USEPA on January 23, 1997. In addition, the State has terminated certain source permits subsequent to source closures to gain permanent emission reductions. All of these actions have reduced emissions in a permanent manner.

It should be noted that Vanderburgh County is classified as a marginal ozone nonattainment area. Under the Clean Air Act, such an area is required to do little in the way of additional emission reductions beyond the impacts of the national programs, such as the Federal Motor Vehicle Emissions Control Program. In terms of emission reductions, the State has complied with the Clean Air Act redesignation requirements. It should also be noted that, as discussed earlier, VOC RACT emission controls on stationary sources are not required in Vanderburgh County.

Comment: A commenter notes that IDEM has correctly asserted that the Evansville ozone problem is regional in nature and that the problem should be dealt with on a regional basis. It is noted that, besides the regional nature of VOC emissions, the Evansville area is impacted by NO_X emissions from significant sources in a much larger area. In addition, the commenter believes that mobile source emissions must be dealt with over a larger geographical area (the commenter, nonetheless, believes that Vanderburgh County should remain designated as nonattainment for ozone).

Response: The USEPA agrees with many of these comments. The ozone data, both the Alcoa monitor ozone standard exceedances and the elevated ozone levels at other monitors, under various meteorological conditions imply that the high ozone levels in the Evansville area may originate from an area significantly larger than just Vanderburgh County. The State is encouraged to consider emission controls from a larger area to help maintain the ozone standard and to lower peak ozone levels if necessary to eliminate a future ozone standard violation.

The USEPA also agrees that NO_x emissions and motor vehicle emissions contribute to the elevated ozone concentrations. Control of these emissions will help maintain the ozone standard.

Comment: A commenter, noting that no ozone standard violations have been recently recorded in Vanderburgh County, recommends that the nonattainment designation of Vanderburgh County be retained to protect the air quality in the lower Ohio Valley area. This commenter believes that, at minimum, the USEPA should redesignate Warrick County to nonattainment of the ozone standard even if the USEPA is ''forced'' to redesignate Vanderburgh County to attainment.

Response: It is correct that no ozone standard violations have been recorded in Vanderburgh County during the most recent three years (1994–1996), thus demonstrating that Vanderburgh County is attaining the ozone standard. Furthermore, for the reasons explained above regarding the uncertainties connected with the determination of the extent of Vanderburgh County's contribution to the ozone concentrations monitored in Warrick County, the USEPA believes it is appropriate to propose approval of the Vanderburgh County redesignation request at this time.

With respect to the status of Warrick County itself, USEPA notes that it has several options available to it in dealing with a violation in an attainment area, USEPA may: choose to redesignate the area to nonattainment; issue a SIP call; take enforcement action if the violation appears to be caused by compliance failures; or encourage the State to require more controls in the area (without an official SIP call).

Currently, there is a stakeholders process underway to determine what controls are needed to address the Warrick County violation. The USEPA believes it is appropriate to give the stakeholders group (composed of representatives from the State, local officials, local industry, environmental groups, academia, and private citizens) an opportunity to solve the local air quality problems. If this process fails, USEPA can then use its authority, e.g., to issue a SIP call to the area or redesignate the area to nonattainment. The USEPA also notes that it expects to be taking steps in 1997 to require reductions in regional emissions as a response to the OTAG conclusions that will reduce ozone transport into the Evansville area. This may help to correct the Warrick County air quality violation.

Comment: A commenter believes that it is USEPA's policy to consider all ozone monitors in an area to determine the attainment status of the area. Therefore, the commenter believes USEPA must consider the data from the Alcoa site in reviewing the attainment status of Vanderburgh County and surrounding counties.

Response: The USEPA agrees with this comment. See the response to comments above.

Comment: Several physicians object to the redesignation of Vanderburgh County based on concerns over chronic effects produced by ozone during the peak ozone periods and observations of increased pulmonary hospital admissions during these periods. These physicians urge the USEPA to not ignore the high ozone levels at the Alcoa monitoring site.

Response: The USEPA believes that, if Vanderburgh County satisfies the statutory criteria for redesignation, including attainment of the current standard, it should be redesignated to attainment. In proposing this redesignation, the USEPA has not ignored the high ozone levels at the Alcoa monitoring site but has carefully analyzed those monitored concentrations and attempted to determine the sources of the ozone precursors that resulted in those monitored readings. This action is premised on the 0.12 ppm one-hour standard, which is the standard now in effect and which was established in accordance with sections 108 and 109 of the Act to protect public health. The USEPA, however, has recently proposed revising the current ozone standard (61 FR 65716). That rulemaking is the appropriate forum for the submission of comments regarding the health protections afforded by the ozone standard.

Comment: A group of physicians and college professors have evaluated the Alcoa 1994 ozone data and have determined that the data are valid for purposes of evaluating the area's attainment status. They believe that the May 23, June 20, and June 21, 1994 data confirm that Vanderburgh County emissions have contributed to an ozone standard violation and that Vanderburgh County should retain its ozone nonattainment status.

Response: As noted in this notice, the USEPA considers the data from the Alcoa site to be valid and relevant to the redesignation review. The good performance of the Alcoa monitor in quality assurance tests support the validity of the Alcoa ozone standard exceedances. However, the USEPA has also considered the meteorological patterns during this time period. As discussed above, the USEPA is requesting comment on the issues related to the potential contribution of emissions from Vanderburgh County to the violation in neighboring Warrick County in light of the data and information in the Docket.

The USEPA encourages the State of Indiana to implement emission controls over an area larger than Vanderburgh County, and to follow through on its commitment to implement its maintenance plan contingency measures and to work with the local Evansville community and surrounding areas to adopt emission control programs and regulations, and submit these regulations as part of a State implementation plan revision.

Comment: Commenters believe that the Alcoa monitor is located in an area where one may expect ozone levels resulting from Evansville area emissions to maximize. They believe the USEPA intends to ignore the Alcoa data and this fact of typical ozone formation, thus violating USEPA procedures.

Response: The USEPA agrees with the commenters that the Alcoa monitor is in a location where relatively high ozone levels may be expected. Since this monitor is approximately 15 miles from Evansville, this site is a good choice for a peak downwind ozone site for the Evansville area. As should be evident from today's notice, USEPA has no intention of ignoring the Alcoa data. The validity of these data and their implications in this matter have been given very serious consideration. Even though the Alcoa monitor is located outside the Evansville nonattainment area, the USEPA did consider the data from this monitor in reviewing and evaluating the State's request.

Comment: A commenter notes that he has seen recent indications of degraded air quality at sporting events attended by his child. During softball games on warm days, he has observed an increased incident of itchy, irritated eyes, and breathing difficulties, such as coughing and breathlessness. A particular incident, in which a player had to leave the field due to breathing difficulties, was not preceded by strenuous activity and resulted in the child being taken to a local hospital for observation. The child's breathing difficulties could not be attributed to any preexisting condition and her condition improved after she was removed from contact with the outside air. For the future of the children in the area, the commenter believes Vanderburgh County should remain marginal nonattainment for ozone.

Response: The USEPA acknowledges the commenter's observations of possible negative health effects from air pollution. Unfortunately, the commenter has not equated these observations with the peak ozone concentrations on the days when these health effects were observed. It is not clear that they were observed in an area and at a time with high ozone concentrations.

Comment: Several citizens have expressed concern that the USEPA has simply given in to political pressure to redesignate Vanderburgh County to attainment to support future industrial growth. Several of these citizens have children who suffer from allergies and respiratory problems. Other citizens are concerned about a high number of cancer-related deaths and the dying of trees.

Response: The USEPA recognizes that there may be illness associated with exposure to high levels of ozone. The current ozone standard (0.12 ppm) is a health-based standard which the Agency has proposed to revise, as noted above. Concerns over public health have been heard; the State and the local community are committed to adopting additional controls in Evansville and the surrounding areas above and beyond those already being implemented in order to further reduce emissions.

The USEPA has seriously considered the data in this issue. The USEPA, while weighing the various issues in this case, is very concerned about the impacts of its decisions on public health, as well as establishing the proper source-receptor relations to assess accountability for measured air quality levels.

Comment: Several commenters have expressed an interest in the placement of ozone monitors in Posey County or, more specifically, in Mt. Vernon.

Response: In the present rulemaking, USEPA must base its decision on the monitoring data available. Additionally, USEPA notes that IDEM has indicated a willingness to expand its ozone monitoring network to include Posey County.

VII. Proposed Action

The USEPA proposes to approve the redesignation of Evansville (Vanderburgh County) to attainment for ozone and to approve the maintenance plan for the area.

Nothing in this action should be construed as permitting or allowing or establishing a precedent for any future request for redesignation. Each request shall be considered separately in light of specific technical, economic, and environmental factors and in relation to relevant statutory and regulatory requirements.

VIII. Interim Implementation Policy (IIP) Impact

On December 13, 1996, USEPA published proposed revisions to the ozone and particulate matter NAAQS (61 FR 65716 and 61 FR 65638). Also on December 13, 1996, USEPA published its proposed policy (61 FR 65752) regarding the interim implementation requirements for ozone and particulate matter during the time period following any promulgation of a revised ozone or particulate matter NAAQS. This IIP includes proposed policy regarding ozone redesignation actions submitted to and approved by the USEPA prior to the promulgation of a new ozone standard, as well as those submitted prior to and approved by the USEPA after the promulgation of a new ozone standard.

Complete redesignation requests submitted and approved by EPA prior to the promulgation date of the revised ozone standard will be allowed to stand based on the maintenance plan's ability to demonstrate attainment of the current one-hour standard and compliance with existing redesignation criteria. Any redesignation requests submitted prior to promulgation of the revised ozone standard, but which are not approved by the USEPA prior to that promulgation date, must also include a maintenance plan which demonstrates attainment of both the current one-hour standard and the revised ozone standard to receive final approval by the USEPA of redesignation to attainment.

As discussed above, the USEPA proposes to approve the Evansville redesignation request as demonstrating attainment under the current one-hour ozone standard. If the USEPA does not take final action prior to the promulgation of the revised ozone standard and the request is otherwise approvable, the USEPA will work with the IDEM to as quickly as possible to supplement the maintenance plan to demonstrate attainment and maintenance of the revised ozone standard.

IX. Administrative Requirements

A. Executive Order 12866

This action has been classified as a Table 3 action for signature by the Regional Administrator under the procedures published in the Federal Register on January 19, 1989 (54 FR 2214–2225), as revised by a July 10, 1995 memorandum from Mary D. Nichols, Assistant Administrator for Air and Radiation. The Office of Management and Budget (OMB) has exempted this regulatory action from Executive Order 12866 review.

B. Regulatory Flexibility Act

Under the Regulatory Flexibility Act, 5 U.S.C. 600 *et seq.*, the USEPA must prepare a regulatory flexibility analysis assessing the impact of any proposed or final rule on small entities. 5 U.S.C. 603 and 604. Alternatively, the USEPA may certify that the rule will not have a significant impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises, and government entities with jurisdiction over populations of less than 50,000.

Redesignation of an area to attainment under section 107(d)(3)(E) of the CAA does not impose any new requirements on small entities. Redesignation is an action that affects the status of a geographical area and does not impose any regulatory requirements on sources. The Administrator certifies that the approval of the redesignation request will not affect a substantial number of small entities.

C. Unfunded Mandates

Under Section 202 of the Unfunded Mandates Reform Act of 1995 (''Unfunded Mandates Act''), signed into law on March 22, 1995, the USEPA must prepare a budgetary impact statement to accompany any proposed or final rule that includes a Federal mandate that may result in estimated costs to State, local, or tribal governments in the aggregate; or to the private sector, of $100 million or more. Under Section 205, the USEPA must select the most cost-effective and least burdensome alternative that achieves the objectives of the rule and is consistent with statutory requirements. Section 203 requires the USEPA to establish a plan for informing and advising any small governments that may be significantly or uniquely impacted by the rule.

The USEPA has determined that the approval action proposed does not include a Federal mandate that may result in estimated costs of $100 million or more to either State, local, or tribal governments in the aggregate, or to the private sector. This Federal action approves pre-existing requirements under State or local law, and imposes no new Federal requirements. Accordingly, no additional costs to State, local, or tribal governments, or to the private sector, result from this action.

Dated: March 5, 1997.

Valdas V. Adamkus,

Regional Administrator.

[FR Doc. 97–6510 Filed 3–13–97; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 73

[MM Docket No. 97–88; RM–9031]

Radio Broadcasting Services; Centennial, WY

AGENCY: Federal Communications Commission.

ACTION: Proposed rule.

SUMMARY: The Commission requests comments on a petition filed by Red Rock Broadcasting proposing the allotment of Channel 224A at Centennial, Wyoming, as the community's first local aural transmission service. Channel 224A can be allotted to Centennial in compliance with the Commission's minimum distance separation requirements with a site restriction of 11.9 kilometers (7.4 miles) east to avoid a short-spacing to the licensed site of Station KIQZ(FM), Channel 224A, Rawlins, Wyoming. The coordinates for Channel 224A at Centennial are North Latitude 41–19–03 and West Longitude 105–59–55.

DATES: Comments must be filed on or before April 28, 1997, and reply comments on or before May 13, 1997.

ADDRESSES: Federal Communications Commission, Washington, DC 20554. In addition to filing comments with the FCC, interested parties should serve the petitioner, or its counsel or consultant, as follows: Pamela C. Cooper, Roberts & Eckard, P.C., 1150 Connecticut Ave., NW., Suite 1100, Washington DC 20036 (Counsel for Petitioner).

FOR FURTHER INFORMATION CONTACT: Sharon P. McDonald, Mass Media Bureau, (202) 418–2180.

SUPPLEMENTARY INFORMATION: This is a synopsis of the Commission's Notice of Proposed Rule Making, MM Docket No. 97–88, adopted February 26, 1997, and released March 7, 1997. The full text of this Commission decision is available for inspection and copying during normal business hours in the FCC Reference Center (Room 239), 1919 M Street, NW., Washington, DC. The complete text of this decision may also be purchased from the Commission's copy contractor, International Transcription Service, Inc., (202) 857–3800, 2100 M Street, NW., Suite 140, Washington, DC 20037.

Provisions of the Regulatory Flexibility Act of 1980 do not apply to this proceeding.

Members of the public should note that from the time a Notice of Proposed Rule Making is issued until the matter is no longer subject to Commission consideration or court review, all *ex parte* contacts are prohibited in Commission proceedings, such as this one, which involve channel allotments. See 47 CFR 1.1204(b) for rules governing permissible *ex parte* contacts.

For information regarding proper filing procedures for comments, see 47 CFR 1.415 and 1.420.

List of Subjects in 47 CFR Part 73

Radio broadcasting.

Federal Communications Commission.

John A. Karousos,

Chief, Allocations Branch, Policy and Rules Division, Mass Media Bureau.

[FR Doc. 97–6430 Filed 3–13–97:45 am]

BILLING CODE 6712–01–F

47 CFR Part 73

[MM Docket No. 96–127; RM–8805]

Radio Broadcasting Services; Kula, HI

AGENCY: Federal Communications Commission.

ACTION: Proposed rule; dismissal.

SUMMARY: This document dismisses a petition filed by Sonia A. Humphrey seeking the allotment of FM Channel 244A to Kula, Hawaii, based upon the lack of interest by the petitioner or any other interested party to provide information, as requested in the *Notice of Proposed Rule Making* to establish that Kula constitutes a *bona fide* ''community'', as that term is defined for purposes of Section 307(b) of the Communications Act, as amended by the Telecommunications Act of 1996,

for allotment objectives. *See* FR 31083, June 19, 1996. With this action, the proceeding is terminated.

ADDRESSES: Federal Communications Commission, Washington, DC 20554.

FOR FURTHER INFORMATION CONTACT: Nancy Joyner, Mass Media Bureau, (202) 418–2180.

SUPPLEMENTARY INFORMATION: This is a synopsis of the Commission's *Report and Order* MM Docket No. 96–127, adopted February 26, 1997, and released March 7, 1997. The full text of this Commission decision is available for inspection and copying during normal business hours in the FCC's Reference Center (Room 239), 1919 M Street, NW., Washington, DC. The complete text of this decision may also be purchased from the Commission's copy contractors, International Transcription Services, Inc., 2100 M Street, NW., Suite 140, Washington, DC 20037, (202) 857–3800.

List of Subjects in 47 CFR Part 73

Radio broadcasting.

Federal Communications Commission.

John A. Karousos,

Chief, Allocations Branch, Policy and Rules Division, Mass Media Bureau.

[FR Doc. 97–6426 Filed 3–13–97; 8:45 am]

BILLING CODE 6712–01–F

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47 CFR Part 73

[MM Docket No. 97–89, RM–9029]

Radio Broadcasting Services; Manistique, MI

AGENCY: Federal Communications Commission.

ACTION: Proposed rule.

SUMMARY: This document requests comments on a petition filed by Indian River Broadcasting Company proposing the allotment of Channel 260A to Manistique, Michigan, as that community's first local FM broadcast service. The coordinates for Channel 260A are 45–57–24 and 86–14–48. Canadian concurrence will be requested for the allotment of Channel 260A at Manistique.

DATES: Comments must be filed on or before April 28, 1997, and reply comments on or before May 13, 1997.

ADDRESSES: Federal Communications Commission, Washington, DC. 20554. In addition to filing comments with the FCC, interested parties should serve the petitioner's counsel, as follows: Henry E. Crawford, 1150 Connecticut Avenue, NW, Suite 900, Washington, DC 20036.

FOR FURTHER INFORMATION CONTACT: Kathleen Scheuerle, Mass Media Bureau, (202) 418–2180.

SUPPLEMENTARY INFORMATION: This is a summary of the Commission's Notice of Proposed Rule Making, MM Docket No. 97–89, adopted February 26, 1997, and released March 7, 1997. The full text of this Commission decision is available for inspection and copying during normal business hours in the Commission's Reference Center (Room 239), 1919 M Street, NW., Washington, DC. The complete text of this decision may also be purchased from the Commission's copy contractors, International Transcription Services, Inc., 2100 M Street, NW., Suite 140, Washington, DC. 20037, (202) 857–3800.

Provisions of the Regulatory Flexibility Act of l980 do not apply to this proceeding.

Members of the public should note that from the time a Notice of Proposed Rule Making is issued until the matter is no longer subject to Commission consideration or court review, all *ex parte* contacts are prohibited in Commission proceedings, such as this one, which involve channel allotments. See 47 CFR 1.1204(b) for rules governing permissible *ex parte* contact.

For information regarding proper filing procedures for comments, see 47 CFR 1.415 and 1.420.

List of Subjects in 47 CFR Part 73

Radio broadcasting.

Federal Communications Commission.

John A. Karousos,

Chief, Allocations Branch, Policy and Rules Division, Mass Media Bureau.

[FR Doc. 97–6425 Filed 3–13–97; 8:45 am]

BILLING CODE 6712–01–F

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47 CFR Part 73

[MM Docket No.97–87, RM–9028]

Radio Broadcasting Services; Hubbardston, MI

AGENCY: Federal Communications Commission.

ACTION: Proposed rule.

SUMMARY: This document requests comments on a petition filed by Jane Lafler proposing the allotment of Channel 279A to Hubbardston, Michigan, as that community's first local FM broadcast service. There is a site restriction 2 kilometers (1.2 miles) west of the community at coordinates 43–05–53 and 84–51–54. Canadian concurrence will be requested for this allotment.

DATES: Comments must be filed on or before April 28, 1997, and reply comments on or before May 13, 1997.

ADDRESSES: Federal Communications Commission, Washington, DC. 20554. In addition to filing comments with the FCC, interested parties should serve the petitioner, as follows: Jane Lafler, P. O. Box 216, Hubbardston, Michigan 48845.

FOR FURTHER INFORMATION CONTACT: Kathleen Scheuerle, Mass Media Bureau, (202) 418–2180.

SUPPLEMENTARY INFORMATION: This is a summary of the Commission's Notice of Proposed Rule Making, MM Docket No. 97–87, adopted February 26, 1997, and released March 7, 1997. The full text of this Commission decision is available for inspection and copying during normal business hours in the Commission's Reference Center (Room 239), 1919 M Street, NW., Washington, DC. The complete text of this decision may also be purchased from the Commission's copy contractors, International Transcription Services, Inc., 2100 M Street, NW., Suite 140, Washington, DC. 20037, (202) 857–3800.

Provisions of the Regulatory Flexibility Act of l980 do not apply to this proceeding.

Members of the public should note that from the time a Notice of Proposed Rule Making is issued until the matter is no longer subject to Commission consideration or court review, all *ex parte* contacts are prohibited in Commission proceedings, such as this one, which involve channel allotments. See 47 CFR 1.1204(b) for rules governing permissible *ex parte* contact.

For information regarding proper filing procedures for comments, see 47 CFR 1.415 and 1.420.

List of Subjects in 47 CFR Part 73

Radio broadcasting.

Federal Communications Commission.

John A. Karousos,

Chief, Allocations Branch, Policy and Rules Division, Mass Media Bureau.

[FR Doc. 97–6424 Filed 3–13–97; 8:45 am]

BILLING CODE 6712–01–F

Notices

Federal Register
Vol. 62, No. 50
Friday, March 14, 1997

DEPARTMENT OF AGRICULTURE

Food and Consumer Service

Agency Information Collection Activities: Proposed Collection; Comment Request; Food Stamp Program Identification Card Requirements

AGENCY: Food and Consumer Service, USDA.

ACTION: Notice.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995, this notice invites the general public and other public agencies to comment on proposed information collections. This notice announces the Food and Consumer Service's (FCS) intention to request OMB review of the agency's proposal to continue requiring State agencies, in accordance with the Food Stamp Act of 1977 (the Act) and regulations issued pursuant to the Act, to issue a Food Stamp Program (FSP) identification card to each household certified eligible to receive and use food stamps.

Section 7(a) of the Act requires that food stamp benefits be issued only to households which have been duly certified as eligible to participate in the Food Stamp Program. Further, under section 7(b) food stamp benefits issued to eligible households shall be used by them to purchase food in authorized retail food stores. Part 274.10(a) of the FSP regulations requires that an eligible household member or authorized representative show the household ID card as proof of household identity and eligibility to receive food stamp benefits. Part 278.2(h) of the FSP regulations provides that if a food retailer has cause to believe that a person presenting food stamps has no right to use the food stamps, the food retailer should request the person to show the food stamp ID card of the household to establish the right of that person to use the food stamps. Part 278.2(i) of the FSP regulations provides that an authorized meal delivery service require the recipient of a delivered meal to show the specially marked food stamp ID card establishing the recipient's right to use food stamps for the service the first time food stamps are offered as payment. Thereafter, the delivery service may request that the specially marked food stamp ID card be shown at any time the delivery service has cause to question the continued eligibility of the person to use food stamps for delivered meals.

Section 11(e) paragraphs (15) and (19) of the Act and Part 274.10(b) of the regulations require State agencies to issue photographic identification cards (photo ID cards) in project areas or portions thereof with more than 100,000 participants, and in those project areas with less than 100,000 participants that have been identified by the Department's Inspector General as needing photo ID cards, to reduce the number of unauthorized issuances of benefits. Neither the Act or FSP regulations require issuance and use of Photo ID cards in project areas where all issuances of benefits are delivered by direct mail or an electronic Benefit Transfer (EBT) system. State agencies may request voluntary use of photo ID cards in any project area with less than 100,000 participants and not required to use photo ID cards. However, State agencies are rapidly implementing EBT systems project area by project area and in groups of project areas. This effort is continuing to reduce the use of photo ID cards.

DATES: Written comments must be submitted on or before May 13, 1997.

ADDRESSES: 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 has practical utility; (b) 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; (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 those who are to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology. Comments may be sent to James I. Porter, Assistant Branch Chief, State Administration Branch, Food Stamp Program, Food and Consumer Service, U.S. Department of Agriculture, 3101 Park Center Drive, Alexandria, VA 22302.

All responses to this notice will be summarized and included in the request for the Office of Management and Budget (OMB) approval. All comments will also become a matter of public record.

FOR FURTHER INFORMATION CONTACT: Requests for additional information regarding this information collection should be directed to James Porter, (703) 305–2385.

SUPPLEMENTARY INFORMATION:

Title: Food Stamp Program Identification Card Requirements.

OMB Number: 0584–0124.

Form Number: None.

Expiration Date: 4/30/97.

Type of Request: Extension of the expiration date of a currently approved information collection without any change in the substance or in the method of collection.

Abstract: The FSP regulations require that photo ID cards be controlled documents by the use of serial numbers. State agencies are required to include on all ID cards, the name of the household member who is authorized to receive the household's issuance, a photograph of the household member, other appropriate information, and laminate the photo ID card at the time of household certification to participate. Also, blank serial numbered photo ID cards must be maintained in secure storage. Households are required to present their photo ID cards to receive benefits and the issuance agents are required to annotate the card serial number on the authorization to participate documents. In addition, households may be required to present their cards for identity when food stamps are presented to an authorized food retailer or meal service to purchase food.

Affected Public: State and local governments, and food stamps households.

Estimated Number of Respondents: 9,195,545.

Number of Responses Per Respondent: 25.590.

Estimated Total Annual Burden: 1,012,998.

Dated: March 4, 1997.

William E. Ludwig,

Administrator, Food and Consumer Service.

[FR Doc. 97–6519 Filed 3–13–97; 8:45 am]

BILLING CODE 3410–30–M

Forest Service

Extension of Currently Approved Information Collection for Interpretive Services Program

AGENCY: Forest Service, USDA.

ACTION: Notice of intent; request for comments.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995, the Forest Service announces its intent to request an extension of a currently approved information collection. The Cooperative Funds and Deposits Act of 1975 (16 U.S.C. 565a through 565a–3) authorizes the Forest Service to enter into cooperative agreements with interpretive associations to provide interpretive services and educational literature for visitors on National Forest System lands. As part of the cooperative agreement, the Forest Service requires that the interpretive associations submit to the agency, annually, information regarding the types of interpretive services and educational literature provided. This collected information is used to compile the national report, ''National Interpretative Associations Annual Report,'' for the Chief of the Forest Service. The agency will use the collected information to evaluate cooperative agreements between the Forest Service and interpretive associations and to ensure effective management of the agency's interpretive services program. Information is requested using the Forest Service 2300–5 Annual Report Interpretive Associations Form.

DATES: Comments must be received in writing on or before May 13, 1997.

ADDRESSES: All comments should be addressed to: Director, Recreation, Heritage, and Wilderness Resources (MAIL STOP 1125), Forest Service, USDA, P.O. Box 96090, Washington, D.C. 20090–6090.

FOR FURTHER INFORMATION CONTACT: Richard Calnan, Recreation, Heritage, and Wilderness Resources Staff, at (202) 205–1228.

SUPPLEMENTARY INFORMATION:

Description of Information Collection

The following describes the information collection to be extended:

Title: FS–2300–5 Annual Report Interpretive Associations.

OMB Number: 0596–0097.

Expiration Date of Approval: June 30, 1997.

Type of Request: Extension of a previously approved information collection.

Abstract: For over 20 years, the Forest Service has entered into cooperative agreements with interpretive associations under the authority of the Cooperative Funds and Deposits Act of 1975 (16 U.S.C. 565a–1 through 565a–3) to provide interpretive services and educational materials to the public. Fifty-eight interpretive associations have signed cooperative agreements with the Forest Service for fiscal year 1997 on 122 National Forests.

Interpretive associations develop and publish educational materials about National Forest System land resources and programs, with the assistance of Forest Service employees. The associations also conduct field seminars, operate concession campgrounds under special use permits, and raise funds for projects and programs on National Forest System lands. Each year interpretive associations donate funds, employee staff time, and materials worth over $1 million in support of the agency's interpretive services program.

Forest Service policy requires that interpretive associations provide to the Regional Forester and Forest Supervisor an annual narrative, accomplishment report, and financial statement by March 1 each year. The Forest Service compiles the reports submitted to the Regional Foresters into a national report, ''National Interpretative Associations Annual Report,'' for the Chief of the Forest Service. The reports to the Regional Foresters also are used to compile an annual ''Directory of Interpretive Associations.'' The Directory is used by other Federal agencies and entities wishing to do business with interpretive associations that have entered into cooperative agreements with the Forest Service. The Forest Service will use FS–2300–5 Annual Report Interpretive Associations Form to collect the information for the reports. The Form is divided into five parts.

Part I asks for the name, address and telephone number of the association; the name of the Forest Service Region with which the association has entered into an agreement; the name(s) of the national forests with which the association is affiliated; the names of any other Forest Service Regions within which the association operates; and the names of any other agencies the association serves. For example, the Northwest Interpretive Association operates in Forest Service Regions 1, 5, and 6, and serves the Forest Service, National Park Service, Bureau of Land Management, and Department of the Army, Corps of Engineers.

Part II asks for the interpretive association's gross receipts for the fiscal year. Gross receipts are the sum of the following line items: (a) sales of printed materials, such as books and pamphlets; (b) sales of audio-visual aids, such as video tapes, slides, and posters; (c) sales of theme-related objects or products, such as stuffed animals with a companion book for children; (d) sales of visitor convenience items, such as food, film, and stamps; (e) receipts from presentations, such as guided tours through National Forest System lands, or special movies or videos, such as the Chugach National Forest, Alaska video, ''Prince William Sound—Where an Ocean of Time Meets a Land of Change;'' and (f) receipts from membership dues, donations, gifts, interest income, and other as specified.

Part III asks for the total amount in dollars of benefits provided by the interpretive association to the Forest Service during the fiscal year. The total dollar benefits equate to the sum of the costs to the association of the following line items: (a) the cost of signs provided by the interpretive association, such as interpretive signs on the Shallow Flats Wetland Trail in Kentucky; (b) the cost of designing, fabricating, and installing new exhibits, such as the exhibit at the Mount St. Helens Visitor Center at Silver Lake, Washington; (c) the cost of providing equipment necessary to accomplishing the interpretive services mission, such as the purchase of a computer to monitor earthquake activity in the Eastern Sierra, California; (d) the cost of equipment, supplies, and travel necessary to conduct research activities, such as field trips to the Mount Evans Byway in Colorado to produce an audio tape tour, guide book, and Jr. Ranger book about the area; (e) the cost of providing free publications to the public; (f) the cost of improving recreational facilities, such as cleaning campgrounds and picnic sites, clearing and maintaining trails, or repairing and rehabilitating structures like the historic Ice House and the McKenzie house at the Custer Townsite in South Dakota; (g) the cost of improvements to wildlife habitat or of range, forest, or watershed projects, such as the eagle habitat study program in California; (h) the cost of special events, such as a visitor facility dedication; (i) the cost of training and educational programs, such as developing a curriculum guide for teachers that focuses on the wildflower resources of the Columbia River Gorge National Scenic Area; (j) the value of the time donated by interpretive association staff and volunteers to represent the agency in parades and to staff booths or interpretive tables at community events; and (k) other costs necessary to accomplishing the Forest Services interpretive services mission.

Part IV asks for a brief description of the interpretive association's program and its accomplishments during the fiscal year, such as completion of an accessible interpretive kiosk at Cle Elum Ranger Station, Washington. Part V asks for a brief description of the planned program of work for the next fiscal year.

Data gathered in this information collection is not available from other sources.

Estimate of Burden: 1 hour.

Type of Respondents: Executive Directors of Interpretive Associations.

Estimated Number of Respondents: 60.

Estimated Number of Responses per Respondent: 1.

Estimated Total Annual Burden on Respondents: 60 hours.

The agency invites comments on the following: (a) 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; (b) 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; (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 the use of automated, electronic, mechanical, or other technological collection techniques or other forms of information technology.

Use of Comments

All comments received in response to this notice will be summarized and included in the request for Office of Management and Budget approval. All comments will also become a matter of public record.

Dated: March 7, 1997.

Barbara C. Weber,

Acting Chief.

[FR Doc. 97–6501 Filed 3–13–97; 8:45 am]

BILLING CODE 3410–11–P

National Agricultural Statistics Service

Notice of Intent to Request a Revision of a Currently Approved Information Collection

AGENCY: National Agricultural Statistics Service, USDA.

ACTION: Notice and request for comments.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995 (Pub. L. No. 104–13) and Office of Management and Budget (OMB) regulations at 5 CFR part 1320 (60 FR 44978, August 29, 1995), this notice announces the National Agricultural Statistics Service's (NASS) intention to request a revision to a currently approved information collection, the Agricultural Resources Management Study and Chemical Use Survey.

DATES: Comments on this notice must be received by May 19, 1997 to be assured of consideration.

ADDITIONAL INFORMATION OR COMMENTS: Contact Rich Allen, Associate Administrator, National Agricultural Statistics Service, U.S. Department of Agriculture, 1400 Independence Avenue SW., Room 4117 South Building, Washington, DC 20250–2000, (202) 720–4333.

SUPPLEMENTARY INFORMATION:

Title: Agricultural Resources Management Study and Chemical Use Survey.

OMB Number: 0535–0218.

Expiration Date of Approval: June 30, 1998.

Type of Request: To revise a currently approved information collection.

Abstract: One of the primary objectives of the National Agricultural Statistics Service is to provide high quality and timely estimates about the nation's food supply and environment.

This information collection is being revised to add questions to collect postharvest chemical use data on selected commodities. Data will be collected regarding types and amounts of pesticides used on commodities after harvest and before being shipped to the consumer. Information from this survey is used by government agencies in planning, farm policy analysis, and program administration. NASS will ask for OMB approval within 60 days of submitting the request.

Estimate of Burden: Public reporting burden for this collection of information is estimated to average 28 minutes per response.

Respondents: Farms, Packers/Shippers, Warehouses.

Estimated Number of Respondents: 80,000.

Estimated Total Annual Burden on Respondents: 37,000 hours.

Copies of this information collection and related instructions can be obtained without charge from Larry Gambrell, the Agency OMB Clearance Officer, at (202) 720–5778.

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 will have practical utility; (b) 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; (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 those who are to respond, such as through the use of appropriate automated, electronic, mechanical, or other technological collection techniques. Comments may be sent to:

Larry Gambrell, Agency OMB Clearance Officer, U.S. Department of Agriculture, 1400 Independence Ave. SW, Room 4162 South Building, Washington, D.C. 20250–2000. All responses to this notice will be summarized and included in the request for OMB approval. All comments will also become a matter of public record.

Signed at Washington, D.C., February 21, 1997.

Donald M. Bay,

Administrator, National Agricultural Statistics Service.

[FR Doc. 97–6449 Filed 3–13–97; 8:45 am]

BILLING CODE 3410–20–M

DEPARTMENT OF COMMERCE

[Docket No. 970307047–7047–01]

RIN 0605–XX03

Privacy Act: Amendment of System of Records; Commerce System 5

AGENCY: Commerce.

ACTION: Notice.

SUMMARY: The Department of Commerce gives notice of an amendment to the systems of records under Commerce Department System 5: Freedom of Information and Privacy Request Records. This action has been taken to add the U.S. Patent and Trademark Office to the list of Commerce Department bureaus.

EFFECTIVE DATE: March 14, 1997.

FOR FURTHER INFORMATION CONTACT:

Brenda S. Dolan 202–482–4115.

SUPPLEMENTARY INFORMATION: The Department of Commerce is amending Commerce Department System 5: Freedom of Information and Privacy Request Records to add the U.S. Patent and Trademark Office to the list of bureaus of the Commerce Department. This is not a significant alteration of a system of records under OMB Circular A–130.

—Added under ''System location:''

g. For FOIA and PA request records of the PTO: Office of the Solicitor, U.S. Patent and Trademark Office, 2121 Crystal Drive, Suite 918, Arlington, VA 22202.

—Added under ''System Manager(s) and Address:''

For records at location ''g.'': Deputy Solicitor, Box 8, U.S. Patent and Trademark Office, Washington, DC 20231.

Authority: 5 U.S.C. 552a.

Dated: March 7, 1997.

Brenda S. Dolan,

Department Freedom of Information and Privacy Act Officer.

[FR Doc. 97–6463 Filed 3–13–97; 8:45 am]

BILLING CODE 3510–FA–M

National Oceanic and Atmospheric Administration

[I.D. 030697B]

Western Pacific Fishery Management Council; Public Meeting

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice of public meeting.

SUMMARY: The Western Pacific Fishery Management Council's (Council) Scientific and Statistical Committee (SSC) will hold its 65th meeting.

DATES: The meeting will be held April 8–10, 1997, from 8:00 a.m. to 5:00 p.m. each day.

ADDRESSES: The meeting will be held at the Ala Moana Hotel, 410 Atkinson Dr., Ilima Room, Honolulu, HI; telephone: (808) 955–4811.

Council address: Western Pacific Fishery Management Council, 1164 Bishop St., Suite 1405, Honolulu, HI 96813.

FOR FURTHER INFORMATION CONTACT: Kitty M. Simonds, Executive Director; telephone: (808) 522–8220.

SUPPLEMENTARY INFORMATION: The SSC will discuss and may make recommendations to the Council on the following agenda items:

1. Pelagic fishery issues, including:
a. Pelagic Fisheries Research;
b. Cross Seamount interaction issue;
c. Pelagic data amendment;
d. Bycatch issues/incidental take issues (turtles, sharks, albatross);
e. Determination of the Total Allowable Level of Foreign Fishing for the Pacific Insular Area Fishery Agreements; and (f) other pelagic issues.
2. Hawaii bottomfish issues, including:
a. Status of the State's draft management plan for the Main Hawaiian Islands Onaga and Ehu; and
b. Reconsideration of the Northwestern Hawaiian Islands management system;
3. Lobster management, including:
a. Summary of review panel's report and summary of Crustacean Plan Team and Hawaii Crustacean Advisory Panel recommendations regarding population size, risk analysis, high grading in the 1996 fishery, economic pros and cons of high grading, and valid sample design to estimate high grading;
b. Revised catch report form;
c. Consider mandatory Vessel Monitoring System;
d. Impact of expanding live fishery product;
e. 1997 harvest guideline;
f. Trap design study;
g. NMFS research activities;
h. Concerns of industry; and
i. Other crustacean issues;
4. Ecosystem and habitat issues (coral reef resources, whale sanctuary, etc.); and
5. Other business as required.

Special Accommodations

This meeting is physically accessible to people with disabilities. Requests for sign language interpretation or other auxiliary aids should be directed to Kitty M. Simonds, 808–522–8220 (voice) or 808–522–8226 (fax), at least 5 days prior to meeting date.

Dated: March 7, 1997.

Bruce Morehead,

Acting Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 97–6448 Filed 3–13–97; 8:45 am]

BILLING CODE 3510–22–F

COMMODITY FUTURES TRADING COMMISSION

Chicago Board of Trade Futures Contracts in Corn and Soybeans; Notice That Delivery Point Specifications Must Be Amended

AGENCY: Commodity Futures Trading Commission.

ACTION: Notice of, and request for public comment on, response of the Chicago Board of Trade to notification to amend delivery specifications.

SUMMARY: The Commodity Futures Trading Commission (''Commission''), by letter dated December 19, 1996, notified the Board of Trade of the City of Chicago (''CBT''), under section 5a(a)(10) of the Commodity Exchange Act (''Act''), 7 U.S.C. 7a(a)(10), that the delivery terms of the CBT corn and soybean futures contracts no longer accomplish the objectives of that section of the Act. Under section 5a(a)(10), the CBT was required to respond by March 4, 1997, seventy-five days from the date of the notice.

By letter dated March 4, 1997, from Patrick H. Arbor, to Chairperson Brooksley Born, the CBT responded by providing a status report to the Commission of its actions. In that response, the CBT reported that a ''working alternative'' had been approved by the exchange board and would be forwarded to the membership for a vote.

The Commission is providing notice of the CBT's working alternative in order to provide the public with an opportunity to comment to the Commission on it. The Commission has determined that publication of the CBT working alternative for public comment is in the public interest, will assist the Commission in considering the views of interested persons, and is consistent with the purposes of the Commodity Exchange Act.

DATES: Comment must be received by March 31, 1997.

ADDRESSES: Comments should be mailed to the Commodity Futures Trading Commission, Three Lafayette Centre, 1155 21st Street, NW., Washington, D.C. 20581, attention: Office of the Secretariat; transmitted by facsimile at (202) 418–5521; or transmitted electronically at [secretary@cftc.gov]. Reference should be made to ''Corn and Soybean Delivery Points.''

FOR FURTHER INFORMATION CONTACT: Blake Imel, Acting Director, or Paul M. Architzel, Chief Counsel, Division of Economic Analysis, Commodity Futures Trading Commission, Three Lafayette Centre, 1155 21st Street, NW., Washington, D.C. 20581, (202) 418–5260, or electronically, Mr. Architzel at [PArchitzel@cftc.gov].

SUPPLEMENTARY INFORMATION: Section 5a(a)(10) of the Act provides that as a condition of contract market designation, boards of trade are required to:

permit the delivery of any commodity, on contracts of sale thereof for future delivery, of such grade or grades, at such point or points and at such quality and locational price differentials as will tend to prevent or diminish price manipulation, market congestion, or the abnormal movement of such commodity in interstate commerce. If the Commission after investigation finds that the rules and regulations adopted by a contract market permitting delivery of any commodity on contracts of sale thereof for future delivery, do not accomplish the objectives of this subsection, then the Commission shall notify the contract market of its finding and afford the contract market an opportunity to make appropriate changes in such rules and regulations.

The Commission, by letter dated December 19, 1996, notified the CBT under section 5a(a)(10) of the Act that its futures contracts for corn and soybeans no longer were in compliance with the requirements of that section of the Act. The text of the section 5a(a)(10) letter was published in the Federal Register and public comment was requested. 61 FR 67998 (December 26, 1996).

The section 5a(a)(10) letter offered the CBT guidance in meeting the requirements of the Act in the form of four conceptual alternatives to the current delivery specifications. These four alternatives constituted ''a range of possibilities which could constitute 'appropriate changes' by providing for the necessary, viable linkage with the cash market.'' 61 FR 67998, 68013. In offering this guidance, the Commission noted that:

(b)y providing these alternatives, the Commission is not limiting the CBT's ability to respond to this Section 5a(a)(10) notification, nor is it specifying exact design criteria. Rather, these are examples of various means by which the Commission believes the objectives of the section could be met. In any event, the particular contract specifications proposed by the CBT in response to this notification, in order to meet the statutory requirement, should provide for a linkage with the cash market through specific terms which are in conformity with a substantial segment of that underlying market.

61 FR 68012.

The four alternatives offered by the Commission included a prior CBT alternative that was previously rejected by the exchange membership. This alternative provided for a warehouse receipt contract deliverable at Chicago (at par), Toledo, Milwaukee, East Central Illinois and the Northern Illinois River. The Commission noted, in particular, that any such proposal should be modified to include price differentials reflecting the fact that corn and soybeans become more highly valued the further south the delivery location is on the Northern Illinois River. Another alternative offered was a shipping certificate contract centered on the lower Mississippi River. The Commission also offered cash-settlement as an alternative for consideration.

Finally, the Commission offered the alternative of increasing deliverable supplies by adding to the contract shipping certificates providing for delivery at barge loading locations on the Illinois River and at St. Louis. Specifically, the Commission suggested that:

(a)n alternative specification that could also result in the necessary increase to deliverable supplies would replace the existing warehouse-receipt-delivery instrument with a shipping certificate and provide for delivery at Illinois River barge loading facilities, in addition to the contracts' existing Chicago, Toledo, and St. Louis delivery points. The Illinois River delivery area could be specified to include all or a substantial part of that River. The contracts' par pricing location could be shifted to a delivery location/area that has an active cash market, with locational price discounts for other delivery points/areas set at levels that fall within the range of commonly observed cash price differences between the specified delivery locations.

61 FR at 68013 (footnote deleted).

In publishing the section 5a(a)(10) letter to the CBT, the Commission requested comment on general issues related to both the cash markets for, and the CBT futures contracts on, corn and soybeans and on the specific, relative merits of these suggested alternatives. The working alternative under consideration by the CBT incorporates portions of one or more of those suggested by the Commission, but is sufficiently distinct that public comment on this additional alternative would aid the Commission in its consideration of these issues.

CBT Working Alternative

The CBT's working alternative includes the following salient features:

FEATURES OF CBT WORKING ALTERNATIVE

	Corn	Soybeans
Underlying Instrument:		
(No changes to current quality differentials).	U.S. No. 1 +1.5 cents/bu	U.S. No. 1 +6 cents/bu.
	No. 2 par	No. 2 par.
	No. 3 −1.5 cents/bu	No. 2–3% foreign matter −6 cents/bu.
Primary Delivery Point	Illinois Waterway from Chicago, IL (including Burns Harbor, IN) to Pekin, IL at river mile marker 151.	
Alternate Delivery Point	None.	
Locational Differentials	None, all locations at par.	
Delivery Instrument	Shipping certificate only.	
Maximum Certificates Allowed to Issue	Lesser of registered daily rate of loading for the shipping station times 30 or 25% of net worth.[1]	
	Corn	Soybeans
Premium to Futures for f.o.b. water conveyance.	4 cents/bu	4 cents/bu.
Premium Charge:		
(Previously referred to as storage charge)	$0.0012 per bu. per day in Chicago.	
	$0.0010 per bu. per day on Illinois River.	
Load-out Rate Barge	At the registered daily rate of loading for the shipping station within 3 business days following receipt of loading orders or within 1 business day of constructive placement whichever occurs later.	
Vessel	300,000 bu. per day with 3 days pre-advice.	
Rail	Takers of delivery in Chicago and Burns Harbor will have the option to receive rail loadout at the rate of 25 cars per day (35 cars per day for batch weights and grades).	
Last Trading Day	The business day prior to the 15th calendar day of the contract month.	
Last Delivery Day	The second business day following last trading day.	
Regularity Eligibility	Minimum $2 million working capital and minimum $40 million net worth.	

[1] Current regular warehouses in Chicago and Burns Harbor would be allowed to issue a maximum number of shipping certificates equal to their current regular capacity.

As Commission staff advised the CBT's Task Force during its deliberations, the CBT alternative raises several important issues and it differs from the Commission's in a number of significant respects. The CBT alternative restricts the delivery area to only the northern portion of the Illinois River. Unlike the Commission's suggested Illinois River Shipping Certificate alternative, the CBT river-based delivery area would not be in addition to the existing delivery points on the contracts—including St. Louis and Toledo—but in lieu of them. Moreover, the CBT alternative does not provide for locational price differentials. Finally, unlike the contracts' current specifications for loading against warehouse receipts, the CBT is considering requiring that originators of shipping certificates maintain separate queues, giving takers under the futures contract priority over other load-out commitments.

In order to assist the Commission in its consideration of these issues, the Commission requests written data, views or arguments from interested members of the public. Commenters are requested to analyze and compare the relative merits of the CBT working alternative. Commenters are specifically requested to address the following issues:

1. Does the potential economic deliverable supplies or capacity on the contract under the CBT working alternative meet the requirement of the section 5a(a)(10) notification that the CBT modify the contracts' specifications in order that they ''will tend to prevent or diminish price manipulation, market congestion, or the abnormal movement of such commodity in interstate commerce''? In particular, how does the potential increase in delivery supplies or capacity which results from the addition of the Illinois River shipping certificate compare to deletion of deliverable supplies or capacity at Toledo? Is the net result sufficient to prevent market disruption under foreseeable market circumstances?

2. How should the net change in economic deliverable supplies or capacity be measured? How much of the load-out capacity of the barge-loading facilities on the northern Illinois River likely will be made available for delivery, particularly in light of the queuing aspect of the CBT working alternative? In this respect, within the defined delivery area is there a sufficient number of facilities, and is their ownership sufficiently dispersed?

3. Are the regularity eligibility requirements a significant factor in determining the economic delivery capacity under the CBT working alternative's terms? Are they sufficient or necessary to assure performance on the contract?

4. What are the implications of the working alternative's proposed single delivery area, even if total deliverable supplies or capacity were increased?

5. What are the implications of the absence of locational price differentials? In particular, is the working alternative consistent with the pricing of corn and soybeans in the cash market of the proposed delivery area? What are the implications for the availability of registered certificates?

Issued in Washington, D.C., this 10th day of March 1997, by the Commodity Futures Trading Commission.

Jean A. Webb,

Secretary of the Commission.

[FR Doc. 97–6470 Filed 3–13–97; 8:45 am]

BILLING CODE 6351–01–P

DEFENSE NUCLEAR FACILITIES SAFETY BOARD

Sunshine Act Meeting

FEDERAL REGISTER CITATION OF PREVIOUS ANNOUNCEMENT: Published February 24, 1997, 62 FR 8222.

PREVIOUSLY ANNOUNCED TIME AND DATE OF MEETING: 9:00 a.m., March 19, 1997.

PLACE: The Defense Nuclear Facilities Safety Board, Public Hearing Room, 625 Indiana Avenue, NW, Suite 300, Washington, DC 20004.

STATUS: Open.

CHANGE IN THE MEETING: The meeting has been postponed until 9:00 a.m. on April 16, 1997.

MATTERS TO BE CONSIDERED: The Defense Nuclear Facilities Safety Board will reconvene and continue the open meeting conducted on February 5, 1997, regarding the status of DOE's Implementation Plan for Board Recommendation 95–2, Integrated Safety Management. Specifically, the Board will be given status reports by DOE relative to the Department's efforts to improve the technical expertise necessary to review and implement safety management systems, including establishment of a Core Technical group, and the development of guidance for implementation of the Safety Management System.

CONTACT PERSON FOR MORE INFORMATION: Robert M. Anderson, General Counsel, Defense Nuclear Facilities Safety Board, 625 Indiana Avenue, NW, Suite 700, Washington, DC 20004, (800) 788–4016. This is a toll-free number.

SUPPLEMENTARY INFORMATION: The Defense Nuclear Facilities Safety Board reserves its right to further schedule and otherwise regulate the course of this meeting, to recess, reconvene, postpone or adjourn the meeting, and otherwise exercise its authority under the Atomic Energy Act of 1954, as amended.

Dated: March 11, 1997.

John T. Conway,

Chairman.

[FR Doc. 97–6573 Filed 3–11–97; 4:55 pm]

BILLING CODE 3670–01–M

DEPARTMENT OF EDUCATION

Recognition of Accrediting Agencies

AGENCY: Department of Education.

ACTION: Request for comments on an accrediting agency appealing a previous recommendation of the National Advisory Committee on Institutional Quality and Integrity to withdraw its recognition.

DATES: Commentors should submit their written comments by April 14, 1997 to the address below.

FOR FURTHER INFORMATION CONTACT: Karen W. Kershenstein, Director, Accreditation and State Liaison Division, U.S. Department of Education, 600 Independence Avenue, SW., Room 3915 ROB–3, Washington, DC 20202–5244, telephone: (202) 708–7417. Individuals who use a telecommunications device for the deaf (TDD) may call the Federal Information Relay Service at 1–800–877–8339 between 8 a.m. and 7 p.m., Eastern time, Monday through Friday.

SUBMISSION OF THIRD-PARTY COMMENTS: The Secretary of Education is required by law to publish a list of accrediting agencies that he determines to be reliable authorities regarding the quality of education or training offered by institutions or programs they accredit. The National Advisory Committee on Institutional Quality and Integrity (the ''Advisory Committee'') advises the Secretary on specific accrediting agencies that seek to be recognized by the Secretary.

The National League for Nursing was reviewed by the Advisory Committee at its June 1996 meeting, at which time it recommended that the agency's recognition be withdrawn. The agency appealed that recommendation, in accordance with the provisions set forth in 34 CFR 602.13 of the regulations governing the recognition of accrediting agencies. The Secretary has reviewed the agency's appeal and has decided to remand the matter to the Advisory Committee for review. The Advisory

Committee will consider the case at its June 16–18, 1997 meeting.

The purpose of this notice is to invite interested third parties to present written comments on the National League for Nursing. In order for Department staff to give full consideration to the comments received, the comments must arrive at the address listed above not later than April 14, 1997. Comments must relate directly to the Secretary's Criteria for the Recognition of Accrediting Agencies. All written comments received by the Department in response to this notice will be considered by both the Advisory Committee and the Secretary.

A subsequent Federal Register notice will announce the meeting and invite individuals and/or groups to submit requests for oral presentation before the Advisory Committee on this agency and the other agencies being reviewed at that meeting. That notice, however, does not constitute another call for written comment. This notice is the only call for written comment on the National League for Nursing, which, as indicated above, is appealing the previous recommendation of the Advisory Committee to withdraw its recognition.

Public Inspection of Petitions and Third-Party Comments

All third-party comments received in response to this call for comment, as well as the agency's original petition and supporting documentation, the Department staff analysis of that petition, the agency's appeals materials, and its most recent submission, which the Secretary requested by March 1, 1997, will be available for public inspection at the U.S. Department of Education, ROB–3, Room 3915, 7th and D Streets, SW., Washington, DC 20202–5244, telephone (202) 708–7417 between the hours of 8:00 a.m. and 4:30 p.m., Monday through Friday, until June 2, 1997.

Dated: March 10, 1997.

David A. Longanecker,

Assistant Secretary for Postsecondary Education.

[FR Doc. 97–6416 Filed 3–13–97; 8:45 am]

BILLING CODE 4000–01–M

DEPARTMENT OF ENERGY

Draft Solicitation for Waste Acceptance and Transportation Services

AGENCY: Office of Civilian Radioactive Waste Management, U.S. Department of Energy.

ACTION: Extension of comment period for Draft Solicitation for Waste Acceptance and Transportation Services.

SUMMARY: The Office of Civilian Radioactive Waste Management (OCRWM) announced the availability of a Draft Request For Proposals (RFP) for Waste Acceptance and Transportation Services in the December 23, 1996 Commerce Business Daily (Section V, Page 10) and in the December 27, 1996 Federal Register (Vol. 61, #250, page 68250). The draft solicitation was made available by requesting a copy directly from the Contracting Officer and via the Internet on the OCRWM Home Page and the Headquarters Procurement Operations Home Page at the following addresses: http://www.rw.doe.gov/ and http://www.pr.doe.gov./solicit.html, respectively.

The announcement requested that comments regarding the RFP be submitted to the address listed below no later than March 31, 1997. This notice hereby extends that comment period until May 15, 1997. All comments should be sent to U.S. Department of Energy, 1000 Independence Avenue, SW, Attn: Michelle Miskinis, HR–561.21, Washington, DC 20585.

All comments received will be made available at the U.S. Department of Energy, Public Reading Room located at the above address, at the end of the comment period.

Issued in Washington, D.C. on March 5, 1997.

Scott E. Sheffield,

Acting Associate Deputy Assistant, Secretary for Headquarters Procurement Operations.

[FR Doc. 97–6465 Filed 3–13–97; 8:45 am]

BILLING CODE 6450–01–P

Environmental Management Site-Specific Advisory Board, Pantex Plant

AGENCY: Department of Energy.

ACTION: Notice of open meeting.

SUMMARY: Pursuant to the provisions of the Federal Advisory Committee Act (Pub. L. 92–463, 86 Stat. 770) notice is hereby given of the following Advisory Committee meeting: Environmental Management Site-Specific Advisory Board (EM SSAB), Pantex Plant, Amarillo, Texas.

DATE AND TIME: Tuesday, March 25, 1997: 1:00 p.m.–5:00 p.m.

ADDRESSES: Boatmen's First National Bank, Centennial Room, Amarillo, Texas.

FOR FURTHER INFORMATION CONTACT: Tom Williams, Program Manager, Department of Energy, Amarillo Area Office, P.O. Box 30030, Amarillo, TX 79120 (806) 477–3121.

SUPPLEMENTARY INFORMATION:

Purpose of the Committee: The Board provides input to the Department of Energy on Environmental Management strategic decisions that impact future use, risk management, economic development, and budget prioritization activities.

Tentative Agenda:

1:00 p.m.—Welcome—Agenda Review—Approval of Minutes
1:10 p.m.—Co-Chair Comments
1:20 p.m.—West Texas A&M University Update
—Results of Board Interviews by West Texas Facilitators
1:50 p.m.—West Texas A&M University Budget Discussion
2:20 p.m.—Subcommittee Reports
—Policy & Personnel
—Nominations & Membership
2:40 p.m.—Task Force Reports
—Environmental Restoration
—Transition
3:00 p.m.—Break
3:15 p.m.—Budget Discussions (Focus on the '97 Budget)
—David Humbert, Administrative Services
4:15 p.m.—Ex-Officio Reports
4:30 p.m.—Updates—Occurrence Reports—DOE
5:00 p.m.—Closing Remarks/Adjourn

Public Participation: The meeting is open to the public, and public comment will be invited throughout the meeting. Written statements may be filed with the Committee either before or after the meeting. Written comments will be accepted at the address above for 15 days after the date of the meeting. Individuals who wish to make oral statements pertaining to agenda items should contact Tom Williams' office at the address or telephone number listed above. Requests must be received 5 days prior to the meeting and reasonable provision will be made to include the presentation in the agenda. The Designated Federal Official is empowered to conduct the meeting in a fashion that will facilitate the orderly conduct of business. Each individual wishing to make public comment will be provided a maximum of 5 minutes to present their comments. This notice is being published less than 15 days in advance of the meeting due to programmatic issues that needed to be resolved.

Minutes: The minutes of this meeting will be available for public review and copying at the Pantex Public Reading Rooms located at the Amarillo College Lynn Library and Learning Center, 2201 South Washington, Amarillo, TX phone (806) 371–5400. Hours of operation are from 7:45 am to 10:00 pm, Monday through Thursday; 7:45 am to 5:00 pm on Friday; 8:30 am to 12:00 noon on Saturday; and 2:00 pm to 6:00 pm on Sunday, except for Federal holidays. Additionally, there is a Public Reading Room located at the Carson County Public Library, 401 Main Street, Panhandle, TX phone (806) 537–3742. Hours of operation are from 9:00 am to 7:00 pm on Monday; 9:00 am to 5:00 pm, Tuesday through Friday; and closed Saturday and Sunday as well as Federal Holidays. Minutes will also be available by writing or calling Tom Williams at the address or telephone number listed above.

Issued at Washington, DC on March 11, 1997.

Rachel M. Samuel,

Acting Deputy Advisory Committee Management Officer.

[FR Doc. 97–6468 Filed 3–13–97; 8:45 am]

BILLING CODE 6450–01–P

Bonneville Power Administration

Billy Shaw Dam and Reservoir

AGENCY: Bonneville Power Administration (BPA), Department of Energy (DOE).

ACTION: Finding of no significant impact (FONSI) and floodplain/wetland statement of findings.

SUMMARY: This notice announces BPA's decision to fund the construction, operation, and maintenance of the Billy Shaw Dam and Reservoir on the Duck Valley Reservation. This project is part of a continuing effort to address system-wide fish and wildlife losses caused by the development of the hydropower system in the Columbia River Basin. BPA has prepared an Environmental Assessment (EA) (DOE/EA–1167) evaluating the potential environmental impacts of the proposed project. Based on the analysis in the EA, BPA has determined that the Proposed Action is not a major Federal action significantly affecting the quality of the human environment, within the meaning of the National Environmental Policy Act (NEPA) of 1969. Therefore, the preparation of an Environmental Impact Statement (EIS) is not required and BPA is issuing this FONSI.

A finding is included that there is no practicable alternative to locating the project within a 100-year floodplain.

ADDRESS: For copies of this FONSI, please call BPA's toll-free document request line: 800–622–4520.

FOR FURTHER INFORMATION, CONTACT: Kathy Fisher—ECN, Bonneville Power Administration, P.O. Box 3621, Portland, Oregon, 97208–3621, phone number 503–230–4375, fax number 503–230–5699.

SUPPLEMENTARY INFORMATION: Under provisions of the Pacific Northwest Electric Power Planning and Conservation Act of 1980 (Act), BPA protects, mitigates, and enhances fish and wildlife and their habitats affected by the construction and operation of the Federal hydroelectric system in the Columbia River Basin. This is accomplished through funding of measures that are consistent with the Northwest Power Planning Council's (Council) Fish and Wildlife Program and other purposes of the Act [16 U.S.C. 839b(h)(10)(A)]. The site-specific fish and wildlife mitigation projects that BPA funds are intended to help reach the Council's mitigation goals and are ''in addition to, not in lieu of, other expenditures authorized or required from other entities under other agreements or provisions of law.''

The Proposed Action is for BPA to fund the construction and operation of the Billy Shaw Dam and Reservoir (Project) on the Duck Valley Reservation (Reservation). It is consistent with the objectives of the Council's Program goals and satisfies the Council's recommendation to implement an additional lake fishery at Coyote Sink on the Duck Valley Reservation. Developing the Project would help BPA meet the need to provide off-site mitigation in the Duck Valley area for the loss of salmon and steelhead caused by the construction and operation of the Federal hydroelectric dams and reservoirs on the Columbia River. The No Action Alternative considered in the EA would not satisfy BPA's need to provide off-site mitigation in the Duck Valley Reservation area for salmon and steelhead.

The Project would include the construction of an earthen dam to create a reservoir in the Billy Shaw Slough on the Reservation. The water for the new reservoir would come from natural high spring flows that would be diverted from the Owyhee River at the China Diversion Dam and supplied through the Duck Valley Canal and the new Billy Shaw Feed Canal. The new reservoir would have a surface area of 174 hectares (430 acres) and volume of 3300 acre-feet. The reservoir would be stocked with trout from an existing fish hatchery.

Some environmental impacts would occur as a result of the Project, but the impacts would not be significant. Approximately 223 hectares (550 acres) of vegetation and wildlife habitat would be removed or disturbed by the Project. Approximately 174 hectares (430 acres) of suitable foraging habitat for various animal species, including federally listed bald eagles, and suitable nesting habitat for burrowing owls and pygmy rabbits would be permanently replaced by a reservoir. An additional 49 hectares (120 acres) of habitat would be temporarily disturbed by construction activities. The vegetation and habitat disturbance and removal would not be significant because similar vegetation and habitat is plentiful in the area. The impact area represents less than 3% of the Billy Shaw Slough monotypical vegetation and habitat communities.

Another vegetation related impact would be the increase in plant diversity along the reservoir shoreline. This impact would not be significant because only native plants would be used for reseeding and revegetating disturbed areas. This would prevent non-native plants from being introduced into the local area by the Project.

Soil disturbance from construction and maintenance activities would increase the risk of erosion. However, the impact would not be significant because it would be limited to localized increases in erosion and runoff. Although foraging habitat for bald or golden eagles would be replaced by the new reservoir, the reservoir may contribute to increased site use by bald or golden eagles, especially at the reservoir or riparian fringe areas. No other threatened or endangered wildlife are known to occur within the area. Impacts to the bald eagle would not be significant because similar foraging opportunities are plentiful in the area. Increased site utilization by bald or golden eagles would not significantly impact any other wildlife resource.

The addition of the reservoir would increase the amount of fish habitat in the area. The Project design and location would prevent the reservoir fish from leaving the reservoir so there would be no impacts to other aquatic environments. Approximately 1.2 hectares (3 acres) of intermittent wetlands would be permanently replaced by the reservoir. The impacts would not be significant because the wetlands are not part of a complete and interrelated wetland area. New wetlands and riparian areas would naturally develop in shallow areas around the reservoir perimeter and would offset the loss of the existing intermittent wetlands.

The Project would be developed within an area prone to spring flooding from the Owyhee River. The Project would reduce seasonal flooding below the dam site and would alter normal runoff patterns. No impacts to lives or property would occur because no facilities or habitation exist within the area.

Impacts from construction activities on visual resources, employment and economic opportunities, air quality, and public health and safety would be minor and of short duration. After project construction, the reservoir would attract additional wildlife and diversify the viewing opportunities in the valley.

The location of the Project borrow site was not identified in the EA because it is not known at this time. However, impacts to vegetation, wildlife, and cultural resources would not be significant because preconstruction surveys would be conducted if an undeveloped borrow site is selected for use. If the surveys determine the presence of sensitive resources such as endangered species or historic properties, then the borrow site would either be relocated or appropriate mitigation measures would be applied to ensure any impacts are at a level below significant.

As stated in Chapter IV—Permit Requirements and Contacts of the EA, the Project is subject to certain regulatory requirements. A permit to fill in wetlands under Section 404 of the Clean Water Act would be required. The Nevada Division of Environmental Protection may require a letter of water quality certification or a rolling stock water pollution control permit. The U.S. Army Corps of Engineers would require an Impoundment Permit for the emplacement of the reservoir. In accordance with the National Historic Preservation Act, a Class III cultural resources survey was conducted and found no significant resources. The Nevada State Historic Preservation Officer concurred in a letter dated June 17, 1996 that the Project site was not eligible for the National Register of Historic Places. In accordance with the requirements of the Fish and Wildlife Coordination Act, the U.S. Fish and Wildlife Service (USFWS) was consulted about this Project. The Project is consistent with the Endangered Species Act because the EA confirmed that no plant or animal species federally listed as threatened or endangered would be adversely affected by the Project.

Floodplain Statement of Findings

This is a Floodplain Statement of Findings prepared in accordance with 10 CFR Part 1022. A Notice of Floodplain and Wetlands Involvement was published in the Federal Register on May 17, 1996 and a floodplain and wetlands assessment was incorporated in the EA. BPA proposes to fund the construction of an earth dam and reservoir in the Billy Shaw Slough of the Duck Valley Reservation near Owyhee, Nevada. The Proposed Action would be located in the floodplain because that area offers the topographical qualities needed to fill and maintain a permanent reservoir. The alternative to the Proposed Action, the No Action Alternative, would not satisfy BPA's need to provide off-site mitigation on the Duck Valley Reservation for the loss of salmon and steelhead. The Proposed Action conforms to applicable State or local floodplain protection standards.

Preliminary designs for the spillway and outlet works of the dam included the small dam criteria available from the U.S. Department of Agriculture Natural Resources Conservation Services (NRCS). The inflow design floods were computed based upon NRCS, Idaho Department of Water Resources, and Nevada Division of Water Resources criteria for structures of this size and hazard classification. Although studies indicated that a probable maximum flood event could be stored without the use of the spillway, an emergency spillway would be included in the plan. These design considerations would minimize any potential harm to the floodplain should a significant flood event occur. Also, the downstream hazard classification for the reservoir site is considered low because no permanent or temporary human habitation or permanent property development lies in the floodplain downstream from the proposed damsite.

BPA will endeavor to allow 15 days of public review after publication of this statement of findings before implementing the Proposed Action.

Determination

Based on the information in the EA, as summarized here, BPA determines that the Proposed Action is not a major Federal action significantly affecting the quality of the human environment within the meaning of NEPA, 42 U.S.C. 4321 *et seq.* Therefore, an EIS will not be prepared and BPA is issuing this FONSI.

Issued in Portland, Oregon, on March 3, 1997.

Alexandra B. Smith,

Vice President, Environment, Fish, & Wildlife.

[FR Doc. 97–6464 Filed 3–13–97; 8:45 am]

BILLING CODE 6450–01–P

Federal Energy Regulatory Commission

[Docket No. CP94–161–006]

Avoca Natural Gas Storage; Notice of Site Visit

March 10, 1997.

On March 25 and 26, 1997, the Office of Pipeline Regulation (OPR) staff will inspect on the ground, along with Avoca Natural Gas Storage (Avoca) personnel, locations related to the facilities proposed by Avoca in New York for the Avoca Gas Storage Project Supplement.

All interested parties may attend. Those planning to attend the March 25 and 26, 1997, site inspection must provide their own transportation.

For further information, call Paul McKee, Office of External Affairs, at (202) 208–1088.

Lois D. Cashell,

Secretary.

[FR Doc. 97–6439 Filed 3–13–97; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. CP97–275–000]

Columbia Gas Transmission Corporation; Notice of Request Under Blanket Authorization

March 10, 1997.

Take notice that on March 4, 1997, Columbia Gas Transmission Corporation (Columbia Gas), 1700 MacCorkle Avenue S.E., Charleston, West Virginia 25314–1599, filed in Docket No. CP97–275–000 a request pursuant to Sections 157.205 and 157.211 of the Commission's Regulations under the Natural Gas Act (18 CFR 157.205 and 157.211) for authorization to construct and operate a new point of delivery in McKean County, Pennsylvania, so that interruptible volumes can be delivered to Minard Run Oil Company (MRO). Columbia Gas makes such request under its blanket certificate issued in Docket No. CP83–76–000 pursuant to Section 7 of the Natural Gas Act, all as more fully set forth in the request on file with the Commission and open to public inspection.

Specifically, Columbia Gas indicates its intent to render the interconnecting delivery facility operational by making use of an existing 4-inch tap, installing a 4-inch turbo meter setting and an 8-inch filter separator. It is averred that the delivery facility will be used to provide up to 950 Mcf of natural daily to MRO for industrial use, and up to 346,750 Mcf annually. Columbia Gas states that the interruptible transportation service will be provided to MRO pursuant to Columbia Gas' blanket authority, issued under Part 284 of the Regulations. It is further stated that the interruptible volumes to be delivered to MRO, will be within MRO's certificated entitlements. Columbia Gas does not anticipate that the interruptible service that it will provide through the proposed delivery facility, will detrimentally impact it's existing customers.

Columbia Gas estimates the new delivery facility to cost approximately $38,398. It is indicated that MRO will reimburse Columbia Gas' total facility cost.

Any person or the Commission's staff may, within 45 days after issuance of the instant notice by the Commission, file pursuant to Rule 214 of the Commission's Procedural Rules (18 CFR 385.214) a motion to intervene or notice of intervention and pursuant to Section 157.205 of the Regulations under the Natural Gas Act (18 CFR 157.205) a protest to the request. If no protest is filed within the time allowed therefor, the proposed activity shall be deemed to be authorized effective the day after the time allowed for filing a protest. If a protest is filed and not withdrawn within 30 days after the time allowed for filing a protest, the instant request shall be treated as an application for authorization pursuant to Section 7 of the Natural Gas Act.

Lois D. Cashell,

Secretary.

[FR Doc. 97–6441 Filed 3–13–97; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. ER94–24–017]

Enron Power Marketing, Inc.; Notice of Filing

March 10, 1997.

Take notice that on January 21, 1997, Enron Power Marketing, Inc. tendered for filing a Notification of Change in Status.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 18 CFR 385.214). All such motions or protests should be filed on or before March 20, 1997. 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 motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

Lois D. Cashell,

Secretary.

[FR Doc. 97–6442 Filed 3–13–97; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. RP97–8–000]

Granite State Gas Transmission, Inc.; Notice of Informal Settlement Conference

March 10, 1997.

Take notice that an informal settlement conference will be convened in this proceeding on Thursday, March 20, 1997, at 10:00 a.m., at the offices of the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C., for the purpose of exploring the possible settlement of the above-referenced docket.

Any party, as defined in 18 CFR 385.102(c), or any participant, as defined in 18 CFR 385.102(b), is invited to attend. Persons wishing to become a party must move to intervene and receive intervenor status pursuant to the Commission's regulations, 18 CFR 385.214.

For additional information, contact Donald Williams at (202) 208–0743 or Anja M. Clark at (202) 208–2034.

Lois D. Cashell,

Secretary.

[FR Doc. 97–6446 Filed 3–13–97; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. ER97–1566–000]

Southwestern Public Service Company; Notice of Filing

March 10, 1997.

Take notice that on February 6, 1997, Southwestern Public Service Company (Southwestern) submitted an executed service agreement under its open access transmission tariff with e prime. The service agreement is for umbrella non-firm transmission service.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 18 CFR 385.214). All such motions or protests should be filed on or before March 21, 1997. 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 motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

Lois D. Cashell,

Secretary.

[FR Doc. 97–6444 Filed 3–13–97; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. CP94–161–006]

Avoca Natural Gas Storage; Notice of Intent To Prepare an Environmental Assessment for the Proposed Avoca Gas Storage Project Supplement and Request for Comments on Environmental Issues

March 10, 1997.

The staff of the Federal Energy Regulatory Commission (FERC or Commission) will prepare an environmental assessment (EA) to evaluate the environmental impacts of the construction of about 87.6 miles of various diameter pipeline and related facilities proposed in the Avoca Gas Storage Project Supplement.[1] This EQ will be used by the Commission in its decision-making process to determine whether the project is in the public convenience and necessity.

Summary of the Proposed Project

Avoca Natural Gas Storage (Avoca) received a certificate authorizing the development of gas-storage caverns in an order issued on September 20, 1994. In conjunction with the construction of the storage caverns, Avoca wants to construct facilities to transport brine from the Avoca Storage Field (under development) near Avoca, New York, to two salt recovery facilities, Akzo Nobel Salt Company (Akzo) and Cargill, Inc. (Cargill), near and within Watkins Glen, New York, respectively. The brine would be created during the solution mining (or leaching) of the underground salt caverns that will be used to store natural gas. In that order, Avoca was authorized to use brine injection wells to dispose of the brine created during the cavern leaching process. However, the aquifers into which the brine injection wells were completed do not have the capability to receive the brine at the planned design rate of production. Therefore, Avoca would transport the brine via the proposed brine pipeline to the two salt recovery facilities. Specifically Avoca proposes to construct:

[1] Avoca Natural Gas Storage's application was filed with the Commission under Section 7 of the Natural Gas Act and Part 157 of the Commission's regulations.

• About 36.9 miles of 10-inch-diameter brine pipeline;
• About 5.5 miles of 8-inch-diameter brine pipeline (from about milepost [MP] 36.9 to the Akzo facility);
• About 2.83 miles of 6-inch-diameter brine pipeline (from about MP 36.9 to the Cargill facility);
• A valve station (at MP 36.9);
• A brine storage tank, pipeline pigging equipment, residual water storage tank, associated valves, and piping at the Avoca facility;
• Electric pumps, associated valves, pipeline pigging equipment, and aboveground residual water and brine storage tanks at the Akzo facility; and
• 42.4 miles of 6-inch-diameter processed water return pipeline (from the Akzo facility back to the Avoca facility for reuse) that would be installed in the same ditch as the 36.9-mile-long 10-inch-diameter and the 5.5-mile-long 8-inch-diameter brine pipelines.

The general location of the project facilities is shown in appendix 1.[2] If you are interested in obtaining detailed maps of a specific portion of the project, or procedural information, please write to the Secretary of the Commission.

Land Requirements for Construction

Construction of the proposed facilities would require about 474.5 acres of land including land that would be used for extra workspaces at stream and road crossings and warehouse and staging areas. About 308.1 acres of this land would be within existing utility, road, and railroad rights-of-way. About 134.6 acres would be required for the new permanent right-of-way and about 31.8 acres of land would be restored and allowed to revert to its former use. The proposed pipeline would follow existing rights-of-way for about 90 percent of the route.

Avoca would use a 75- to 100-foot-wide right-of-way to construct most of the project in non-agricultural and agricultural areas, respectively. However, a narrower right-of-way would be used in some areas.

Avoca would install only the brine pipeline (i.e., no water return pipeline) to the Cargill facility, so the right-of-way would be 40 feet wide or less in non-agricultural areas and 55 feet wide in agricultural areas. Also, the portion of the pipeline right-of-way along the Conrail railroad right-of-way leading to the Akzo facility would be about 30-feet-wide.

The EA Process

The National Environmental Policy Act (NEPA) requires the Commission to take into account the environmental impacts that could result from an action whenever it considers the issuance a Certificate of Public Convenience and Necessity. NEPA also requires us to discover and address concerns the public may have about proposals. We call this ''scoping.'' The main goal of the scoping process is to focus the analysis in the EA on the important environmental issues. By this Notice of Intent, the Commission requests public comments on the scope of the issues it will address in the EA. All comments received are considered during the preparation of the EA. State and local government representatives are encouraged to notify their constituents of this proposed action and encourage them to comment on their areas of concern.

The EA will discuss impacts that could occur as a result of the construction and operation of the proposed project under these general headings:
• Geology and soils;
• Water Resources, fisheries, and wetlands;
• Vegetation and wildlife;
• Endangered and threatened species;
• Public safety;
• Land use;
• Cultural resources;
• Air quality and noise;
• Hazardous waste.

We will also evaluate possible alternatives to the proposed project or portions of the project, and make recommendations on how to lessen or avoid impacts on the various resource areas.

Our independent analysis of the issues will be in the EA. Depending on the comments received during the scoping process, the EA may be published and mailed to Federal, state, and local agencies, public interest groups, interested individuals, affected landowners, newspapers, libraries, and the Commission's official service list for this proceeding. A comment period will be allotted for review if the EA is published. We will consider all comments on the EA before we recommend that the Commission approve or not approve the project.

Currently Identified Environmental Issues

We have already identified several issues that we think deserve attention based on a preliminary review of the proposed facilities and the environmental information provided by Avoca. This preliminary list of issues may be changed based on your comments and our analysis.
• 42 private wells, 1 privately-owned community well, and 1 state-regulated non-municipal well would be within 150 feet of construction work areas;
• 46 perennial streams and 42 intermittent streams would be crossed;
• 3 of the perennial streams contain protected fisheries;
• Goff Creek and the Cohocton River would be crossed by directional drilling;
• 54 wetlands would be crossed;
• About 3.92 miles of State Reforestation Lands would be crossed;
• About 9.79 miles of agricultural land would be crossed;
• Proposed construction right-of-way would be wide for this size pipeline;
• The area into which an existing gravel mining operation plans to expand would be crossed;
• Finger Lakes Trail would be crossed at MPs 7.47, 22.39, 26.62, and 39.60 (Queen Catherine Marsh Trail);
• About 2.93 miles of New York State Forest land would be crossed including land within Moss Hill, Birds Eye Hollow, Groundry Hill, Sugar Hill, and Coon Hollow State Forests;
• The access road for the Sanford Lake Day Use Area, a public recreation area, would be crossed near MP 19.97;
• Watkins Glen State Park would be crossed by using the existing Conrail railroad trestle across Glen Creek Gorge for about 450 feet or, alternatively, Watkins Glen State Park may be crossed at another location entirely by directional drill; and
• 6 residences are located within 50 feet of construction work areas.

Public Participation

You can make a difference by sending a letter addressing your specific comments or concerns about the project. You should focus on the potential environmental effects of the proposal, alternatives to the proposal (including alternative locations/routes), and measures to avoid or lessen environmental impact. The more specific your comments, the more useful they will be. Please follow the instructions below to ensure that your comments are received and properly recorded:
• Address your letter to: Lois Cashell, Secretary, Federal Energy Regulatory Commission, 888 First St., N.E., Washington, DC 20426;
• Reference Docket No. CP94–161–006; and
• Mail your comments so that they will be received in Washington, DC on or before April 9, 1997.

[2] The appendices referenced in this notice are not being printed in the Federal Register. Copies are available from the Commission's Public Reference and Files Maintenance Branch, 888 First Street, N.E., Washington, D.C. 20426, or call (202) 208–1371. Copies of the appendices were sent to all those receiving this notice in the mail.

If you do not want to send comments at this time but still want to remain on our mailing list, please return the Information Request (appendix 3). If you do not return the Information Request, you will be taken off the mailing list.

Becoming an Intervenor

In addition to involvement in the EA scoping process, you may want to become an official party to the proceeding or become an ''intervenor.'' Among other things, intervenors have the right to receive copies of case-related Commission documents and filings by other intervenors. Likewise, each intervenor must provide copies of its filings to all other parties. If you want to become an intervenor you must file a motion to intervene according to Rule 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.214) (see appendix 2).

You do not need intervenor status to have your scoping comments considered.

Lois D. Cashell,

Secretary.

[FR Doc. 97–6440 Filed 3–13–97; 8:45 am]

BILLING CODE 6717–01–M

[Project No. 11547–000 Connecticut]

Summit Hydropower; Notice of Availability of Draft Environmental Assessment

March 10, 1997.

In accordance with the National Environmental Policy Act of 1969 and the Federal Energy Regulatory Commission's (Commission's) regulations, 18 CFR Part 380 (Order No. 486, 52 F.R. 47897), the Office of Hydropower Licensing has reviewed the application for minor license for the proposed Hale Project located on the Quinebaug River in the Town of Putnam, Windham County, Connecticut, and has prepared a Draft Environmental Assessment (DEA) for the proposed project. In the DEA, the Commission's staff has analyzed the potential environmental impacts of the proposed project and has concluded that approval of the proposed project, with appropriate mitigative measures, would not constitute a major federal action significantly affecting the quality of the human environment.

Copies of the DEA are available for review in the Public Reference Branch of the Commission's offices at 888 First Street, N.W., Washington, D.C. 20426.

Comments should be filed within 30 days from the date of this notice and should be addressed to Lois D. Cashell, Secretary, Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426. Please affix Project No. 11547–000 to all comments. For further information, please contact Rainer Feller, Environmental Assessment Coordinator, at (202) 219–2796.

Lois D. Cashell,

Secretary.

[FR Doc. 97–6445 Filed 3–13–97; 8:45 am]

BILLING CODE 6717–01–M

[Project No. 11511–001 Kentucky and Illinois]

Hydro Matrix Partnership, Ltd.; Notice of Surrender of Preliminary Permit

March 10, 1997.

Take notice that Hydro Matrix Partnership, Ltd., permittee, for the Uniontown Lock and Dam Project located on the Ohio River in Gallatin County, Illinois and Union County, Kentucky, requested that its preliminary permit be terminated. The preliminary permit was issued on June 5, 1995, and would have expired on May 31, 1998. The permittee states that the project would be economically infeasible.

The permittee filed the request on December 30, 1996, and the preliminary permit for Project No. 11511 shall remain in effect through the thirtieth day after issuance of this notice unless that day is a Saturday, Sunday or holiday as described in 18 CFR 385.2007, in which case the permit shall remain in effect through the first business day following that day. New applications involving this project site, to the extent provided for under 18 CFR Part 4, may be filed on the next business day.

Lois D. Cashell,

Secretary.

[FR Doc. 97–6444 Filed 3–13–97; 8:45 am]

BILLING CODE 6717–01–M

Office of Hearings and Appeals

Notice of Cases Filed During the Week of February 17 Through February 21, 1997

During the Week of February 17 through February 21, 1997, the appeals, applications, petitions or other requests listed in this Notice were filed with the Office of Hearings and Appeals of the Department of Energy.

Any person who will be aggrieved by the DOE action sought in any of these cases may file written comments on the application within ten days of publication of this Notice or the date of receipt of actual notice, whichever occurs first. All such comments shall be filed with the Office of Hearings and Appeals, Department of Energy, Washington, DC 20585–0107.

Dated: March 5, 1997.

George B. Breznay,

Director, Office of Hearings and Appeals.

SUBMISSION OF CASES RECEIVED BY THE OFFICE OF HEARINGS AND APPEALS, DEPARTMENT OF ENERGY

[Week of Feb. 17 through Feb. 21, 1997]

Date	Name and location of applicant	Case No.	Type of submission
2/18/97	Nancy L. Donaldson, Salem, Oregon	VFA–0271	Appeal of an Information Request Denial. If granted: The Freedom of Information Request Denial issued by Bonneville Power Administration would be rescinded, and Nancy L. Donaldson would receive access to certain DOE information.
2/18/97	Western Star Propane, Inc., Littlerock, California.	VEE–0040	Exception to the Reporting Requirements. If granted: Western Star Propane, Inc. would not be required to file Form EIA–782B, Reseller's/Retailer's Monthly Petroleum Product Sales Report.
2/19/97	Personnel Security Hearing	VSO–0136	Request for Hearing under 10 C.F.R. Part 710. If granted: An individual employed by the Department of Energy would receive a hearing under 10 C.F.R. Part 710.

[FR Doc. 97–6466 Filed 3–13–97; 8:45 am]

BILLING CODE 6450–01–P

Notice of Issuance of Decisions and Orders During the Week of February 17 Through February 21, 1997

Office of Hearings and Appeals

During the week of February 17 through February 21, 1997, the decisions and orders summarized below were issued with respect to appeals, applications, petitions, or other requests filed with the Office of Hearings and Appeals of the Department of Energy. The following summary also contains a list of submissions that were dismissed by the Office of Hearings and Appeals.

Copies of the full text of these decisions and orders are available in the Public Reference Room of the Office of Hearings and Appeals, Room 1E–234, Forrestal Building, 1000 Independence Avenue, SW, Washington, D.C. 20585–0107, Monday through Friday, between the hours of 1:00 p.m. and 5:00 p.m., except federal holidays. They are also available in Energy Management: Federal Energy Guidelines, a commercially published loose leaf reporter system. Some decisions and orders are available on the Office of Hearings and Appeals World Wide Web site at http://www.oha.doe.gov.

Dated: March 5, 1997.

George B. Breznay,

Director, Office of Hearings and Appeals.

DECISION LIST NO. 21

Appeals

Acadian Gas Pipeline System, 2/18/97, VFA–0260

Acadian Gas Pipeline System (Acadian) filed an Appeal from a determination issued to it on November 26, 1996, by the Department of Energy's Strategic Petroleum Reserve Project Management Office (SPRP). That determination was issued in response to a request for information that Acadian submitted under the Freedom of Information Act (FOIA). The request sought all records regarding the DOE's sale of certain Strategic Petroleum Reserve property. SPRP conducted a search of its records and provided Acadian with a complete file of responsive documents. However, SPRP withheld certain information pursuant to Exemption 4 of the FOIA. The Appeal challenged the adequacy of the search conducted by SPRP. In considering the Appeal, the DOE found that Acadian's request had not been subjected to a search sufficiently thorough and conscientious to meet the established standards of reasonableness. Accordingly, the Appeal was granted and SPRP was directed to perform a new search and issue a new determination identifying all responsive documents and justifying any withholdings.

STAND of Amarillo, Inc., 2/20/97, VFA–0261

The Office of Hearings and Appeals (OHA) denied an Appeal that was filed by STAND of Amarillo, Inc. (STAND) pursuant to the Freedom of Information ACT (FOIA). In the Decision, OHA found that the search for responsive documents performed by the Albuquerque Operations Office was adequate, that 91 documents requested by STAND belonged to a DOE contractor and were not agency records subject to the FOIA, and that these documents were not otherwise subject to release under the DOE regulations.

William H. Payne, 2/20/97, VFA–0262

William H. Payne filed an Appeal from a FOIA determination issued by the Albuquerque Operations Office (AOO). The DOE found that the Albuquerque Operations Office (1) properly withheld portions of legal invoices based upon the attorney work-product privilege recognize under FOIA Exemption 5, but failed to segregate and release non-privileged portions of the documents; (2) correctly asserted that records in the possession of a government contractor were not releasable under the FOIA because they were not agency records or under the control of DOE; (3) correctly refused to confirm or deny the existence of records that would indicate whether a former DOE official had been accused of sexual harassment or was the subject of a ''security clearance action.'' Accordingly, the matter was remanded to the AOO, which was directed to issue a revised determination concerning the legal invoices withheld in their entirety and to release any segregable, non-exempt information.

Refund Applications

The Office of Hearings and Appeals issued the following Decisions and Orders concerning refund applications, which are not summarized. Copies of the full texts of the Decisions and Orders are available in the Public Reference Room of the Office of Hearings and Appeals.

Crude Oil Supple Ref Dist	RB272–00094	2/18/97
O'Toole Mechanical Services	RC272–362	1/18/97
Robert L. Helms Construction	RJ272–00037	2/20/97

Dismissals

The following submissions were dismissed.

Name	Case No.
Patrick G. Eddington	VFA–0270
Supervalu, Inc.	RK272–3906
Supervalu, Inc.	RR272–275

[FR Doc. 97–6467 Filed 3–13–97; 8:45 am]

BILLING CODE 6450–01–M

ENVIRONMENTAL PROTECTION AGENCY

[FRL–5710–5]

Agency Information Collection Activities Under OMB Review

Polychlorinated Biphenyls (PCBs): Manufacturing, Processing and Distribution in Commerce Exemptions

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of submission to OMB.

SUMMARY: In compliance with the Paperwork Reduction Act (44 U.S.C. 3501 et seq.), this notice announces that the Information Collection Request (ICR) entitled: Polychlorinated Biphenyls (PCBs): Manufacturing, Processing and Distribution in Commerce Exemptions [EPA ICR No. 0857.07; OMB Control No. 2070–0021] has been forwarded to the Office of Management and Budget (OMB) for review and approval pursuant to the OMB procedures in 5 CFR 1320.12. The ICR, which is abstracted below, describes the nature of the information collection and its estimated cost and burden.

The Agency is requesting that OMB renew for 3 years the existing approval for this ICR, which is scheduled to expire on May 31, 1997. A Federal Register notice announcing the Agency's intent to seek the renewal of this ICR and the 60 day public comment opportunity, requesting comments on the request and the contents of the ICR, was issued on September 12, 1996 (61 FR 48152). EPA did not receive any comments on this ICR during the comment period.

DATES: Additional comments may be submitted on or before April 14, 1997.

FOR FURTHER INFORMATION OR A COPY CONTACT: Sandy Farmer at EPA, (202) 260–2740, and refer to EPA ICR No. 0857.07 and OMB Control No. 2070–0021.

ADDRESSES: Send comments, referencing EPA ICR No. 0857.07 and OMB Control No. 2070–0021, to the following addresses:

Ms. Sandy Farmer, U.S. Environmental Protection Agency, Information Management Division (Mailcode: 2137) 401 M Street, SW., Washington, DC 20460

And to:

Office of Information and Regulatory Affairs, Office of Management and Budget (OMB) Attention: Desk Officer for EPA, 725 17th Street, NW., Washington, DC 20503.

SUPPLEMENTARY INFORMATION:

Review Requested: This is a request to renew a currently approved information collection pursuant to 5 CFR 1320.12.

ICR Numbers: EPA ICR No. 0857.07; OMB Control No. 2070–0021.

Current Expiration Date: Current OMB approval expires on May 31, 1997.

Title: Polychlorinated Biphenyls (PCBs): Manufacturing, Processing and Distribution in Commerce Exemptions.

Abstract: Section 6(e)(3)(A) of the Toxic Substances Control Act (TSCA) prohibits the manufacture, processing and distribution in commerce of PCBs. TSCA section 6(e)(3)(B) provides that any person may petition the EPA for an exemption from these prohibitions and that the EPA may grant such an exemption for a one-year period if (1) an unreasonable risk of injury to health or environment would not result, and (2) good-faith efforts have been made to develop a substitute chemical substance for PCBs that does not present an unreasonable risk of injury to health or the environment.

Interim Procedural Rules at 40 CFR Part 750 Subparts B and C outline the procedures for filing exemption petitions, the procedures that EPA will follow when a petition is submitted and the procedures for filing a request to renew an exemption previously granted. Under these rules, EPA may request information from each petitioner to determine whether the petitioner meets the statutory requirements to qualify for an exemption.

Responses to the collection of information are mandatory (see 40 CFR part 750). Respondents may claim all or part of a notice confidential. EPA will disclose information that is covered by a claim of confidentiality only to the extent permitted by, and in accordance with, the procedures in TSCA section 14 and 40 CFR part 2.

Burden Statement: The annual public reporting burden for this collection of information is estimated to average approximately two to eight hours per response for three respondents. These estimates include the time needed to review instructions; develop, acquire, install and utilize technology and systems for the purposes of collecting, validating and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information. No person is required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are displayed in 40 CFR Part 9.

Respondents/Affected Entities: Entities potentially affected by this action are those persons who petition the Environmental Protection Agency for exemptions from the prohibition on the manufacture, processing and distribution in commerce of PCBs.

Estimated No. of Respondents: 3.

Estimated Total Annual Burden on Respondents: 18 hours.

Frequency of Collection: Annually.

Changes in Burden Estimates: There is a decrease of 37 hours in the total estimated respondent burden as compared with that identified in the information collection request most recently approved by OMB, from 55 hours currently to an estimated 18 hours. This reflects the fact that new procedures that EPA has or plans to put in place with respect to the regulation of PCBs will reduce the number of exemption petitions that respondents need to file, and will eliminate the need to file renewal requests for exemptions previously granted. This, in turn, will reduce the burden associated with this information collection.

According to the procedures prescribed in 5 CFR 1320.12, EPA has submitted this ICR to OMB for review and approval. Any comments related to the renewal of this ICR should be submitted as described above.

Dated: March 10, 1997.

Joseph Retzer,

Director, Regulatory Information Division.

[FR Doc. 97–6507 Filed 3–13–97; 8:45 am]

BILLING CODE 6560–50–P

[FRL–5710–3]

Retrofit/Rebuild Requirements for 1993 and Earlier Model Year Urban Buses; Approval of a Notification of Intent To Certify Equipment

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of agency approval of an application for equipment certification.

SUMMARY: The Agency received an application dated March 22, 1996 from the Engelhard Corporation (Engelhard) with principle place of business at 101 Wood Avenue, Iselin, New Jersey for certification of urban bus retrofit/rebuild equipment pursuant to 40 CFR 85.1404–85.1415. The equipment is applicable to Detroit Diesel

Corporation's (DDC's) petroleum-fueled 6V92TA model engines having mechanical unit injectors (MUI) that were originally manufactured between January 1979 and December 1989. On May 6, 1996 EPA published a notice in the Federal Register that the notification had been received and made the notification available for public review and comment for a period of 45 days (61 FR 20249). EPA has completed its review and the Director of the Engine Programs and Compliance Division has determined that it meets all the requirements for certification. Accordingly, EPA certifies this equipment effective March 14, 1997.

The certified equipment complies with the 0.10 gram per brake horsepower-hour (g/bhp-hr) particulate matter (PM) standard for the engines for which it is certified (see below). In addition, the equipment will be offered to all parties for $7,940 or less (in 1992 dollars) incremental to the cost of a standard rebuild. The certification of this equipment triggers requirements for transit operators utilizing compliance Program 1 (excluding engines originally manufactured as meeting California emissions standards) that have engines in their fleet covered by this certification.

DATES: The effective date of certification is March 14, 1997.

ADDRESSES: The Engelhard application, as well as other materials specifically relevant to it, are contained in Public Docket A–93–42, Category VIII–A, entitled ''Certification of Urban Bus Retrofit/Rebuild Equipment''. Docket items may be inspected from 8:00 a.m. until 5:30 p.m., Monday through Friday. As provided in 40 CFR Part 2, a reasonable fee may be charged by the Agency for copying docket materials.

FOR FURTHER INFORMATION CONTACT: Tom Stricker, Engine Programs and Compliance Division (6403J), U.S. Environmental Protection Agency, 401 M St. SW, Washington, D.C. 20460. Telephone: (202) 233–9322.

SUPPLEMENTARY INFORMATION:

I. Background and Equipment Identification

By a notification of intent to certify signed March 22, 1996, Engelhard Corporation (Engelhard) applied for certification of equipment applicable to Detroit Diesel Corporation's (DDC) 6V92TA model urban bus engines having mechanical unit injectors (MUI) that were originally manufactured between model years 1979 and 1993. Today's certification, however, applies only to 6V92TA MUI engines originally manufactured between model years 1979 and 1989, because DDC ceased production of the 6V92TA MUI after model year 1989. The certified equipment, referred to as the ETX kit, consists of an engine ''upgrade'' kit, a CMX–5 catalytic converter-muffler, and a proprietary coating, referred to as GPX–5m, applied to the piston crowns and cylinder head combustion chambers. The engine upgrade portion of the kit consists of specified DDC cylinder kits, cylinder heads, camshafts, turbocharger, blower, blower drive gear (hardened or non-hardened, as appropriate), fuel injectors, and gasket kit. The specific combination of parts to be used depends upon the direction of engine rotation, orientation of the engine (tilt), and engine power level. Injector height and throttle delay must be set to 1.460 inches and 0.636 inches respectively for each of the three certified horsepower (HP) configurations (253 HP, 277 HP, and 294 HP).

Using engine dynamometer testing conducted on January 26, 1996 in accordance with the Federal Test Procedure (FTP) for heavy-duty diesel engines, Engelhard documented in its March 22, 1996 notification, PM emissions below the 0.10 g/bhp-hr level. Engine throttle delay and fuel injector height settings for the ETX certification test were set to 1.466 inches and 0.594 inches respectively in order to comply with FTP cycle statistics requirements. Baseline exhaust emissions data were developed by testing an engine rebuilt to a 1979 urban bus configuration. This testing occurred on April 4, 1994. This set of baseline and ETX test data, is hereafter referred to as the ''original'' baseline and ETX certification tests, and are shown in Table A.

TABLE A.—''ORIGINAL'' BASELINE AND ETX CERTIFICATION DATA

ETX kit including coated exhaust manifolds, turbocharger Y-pipe, cylinder heads, and piston crowns, and throttle delay of 1.466 inches and injector height of 0.594 inches	''Original'' baseline 1979 model year	''Original'' ETX certification test	1988/89 federal standard
Gaseous and particulate emissions (g/bhp-hr):			
HC	0.5	0.2	1.3
CO	1.5	0.4	15.5
NO_X	10.3	10.1	10.7
PM	0.213	0.08	0.6
Smoke emissions (% opacity):			
Accel	NA	0.9	20
Lug	NA	0.6	15
Peak	NA	1.3	50

In response to comments from the public (discussed in detail below), Engelhard removed the coated exhaust components from the ETX kit, and respecified the throttle delay and injector height specifications to 1.460 inches and 0.636 inches respectively. Additional FTP testing of the ETX kit was conducted on September 27, 1996, again documenting PM emissions below the 0.10 g/bhp-hr level, while complying with FTP statistical requirements. Additional baseline data were developed on October 7, 1996 by testing an engine rebuilt to a 1986 urban bus configuration. This set of baseline and ETX test data, submitted to EPA in letters of October 21, 1996 and October 2, 1996 respectively, is hereafter referred to as the ''secondary'' baseline and ETX certification tests, and are shown in Table B.

TABLE B.—''SECONDARY'' BASELINE AND ETX CERTIFICATION DATA

ETX kit including only coated cylinder heads and piston crowns, and throttle delay of 1.460 inches and injector height of 0.636 inches.[1]	''Secondary'' baseline 1979 model year	''Secondary'' ETX certification test	1988/89 federal standard
Gaseous and particulate emissions (g/bhp-hr):			
HC	0.5	0.2	1.3

TABLE B.—"SECONDARY" BASELINE AND ETX CERTIFICATION DATA—Continued

ETX kit including only coated cylinder heads and piston crowns, and throttle delay of 1.460 inches and injector height of 0.636 inches.[1]	"Secondary" baseline 1979 model year	"Secondary" ETX certification test	1988/89 federal standard
CO	1.4	0.5	15.5
NO_X	11.4	10.5	10.7
PM	0.194	0.083	0.6
Smoke emissions (% opacity):			
Accel	NA	1.4	20
Lug	NA	1.4	15
Peak	NA	1.9	50

[1] These are the injector height and throttle delay settings approved as part of today's certification.

Both sets of emissions test data provided by Engelhard demonstrate PM emission levels are below 0.10 g/bhp-hr. However, the ''secondary'' data represent the ETX equipment configuration upon which today's certification is granted. The data indicate that applicable engines with the certified equipment installed comply with the federal 1988 model year emission standards for hydrocarbon (HC), carbon monoxide (CO), oxides of nitrogen (NO_X), and smoke emissions.

Engelhard's March 22, 1996 notification of intent to certify requests certification for DDC 6V92TA MUI engines originally certified as meeting both federal and California emissions standards. However, as described in more detail in the Summary and Analysis of Comments section below, today's certification is limited to 1979 through 1989 DDC 6V92TA MUI engines originally certified as meeting federal emissions standards. Today's certification does not extend certification of equipment to engines originally certified as meeting California emissions standards. The impact of this decision on transit operators is discussed in more detail in the Transit Operator Requirements section below.

Additionally, EPA approves several supply options proposed by Engelhard for transit operators to obtain this certified equipment. Transit operators must purchase the CMX–5 and the GPX–5m coated components of the ETX kit from Engelhard or its distributors. However, in order to provide as much flexibility to transit operators as possible while ensuring emissions reductions, EPA has approved several options for obtaining the remainder of the components of the kit. For the first supply option, transit operators purchase the entire ETX kit from Engelhard or its distributors. This supply option must be available to any and all transit operators, and is the option upon which life cycle costs have been determined, and upon which the 0.10 g/bhp-hr standard is triggered. The second and third options, described below, may be available at Engelhard's discretion. Transit operators who choose either of the options below, do so voluntarily, and EPA makes no representation concerning the impacts of either on life cycle costs.

For the second supply option, transit operators purchase the specified DDC upgrade parts (excluding the coated cylinder heads and piston kits, which must be obtained from Engelhard) through normal supply channels. Engelhard will provide the appropriate DDC parts list to the transit operator upon purchase of the CMX–5 and coated engine parts. ''Equivalent'' aftermarket parts are not permitted under this certification, because EPA has no assurance that such parts can achieve the 0.10 g/bhp-hr PM standard. Engelhard provides the applicable 100,000 mile defect warranty and 150,000 mile emissions performance warranty for all parts included in the kit, whether purchased from Engelhard, or through normal supply channels. Manufacturers of ''equivalent'' aftermarket parts may choose to certify their parts for use in the ETX kit in a separate proceeding subject to testing and certain warranty concerns.

For the third supply option, the transit operator obtains most parts in the same manner described in the second option above, but rebuilds or remanufactures in-house the camshafts, blower, and/or turbocharger. Transit operators can perform in-house rebuilding of these three components provided the transit operator meets the requirements of the ''Engelhard Certified Remanufacturer Program'', and the camshafts, blower, and/or turbocharger are rebuilt to the specified DDC configuration.

The Engelhard Certified Remanufacturer Program, to be administered by Engelhard, is covered by today's certification as it relates to the third supply option. For transit operators who choose to rebuild the camshafts, blower, and/or turbocharger in-house, the Certified Remanufacturer Program requires the transit operator to possess a minimum of five years remanufacturing experience. In addition, Engelhard will perform an initial inspection of the remanufacturing operation to assess facility capabilities, and will conduct a complete review of the quality control procedures and component reject rate of the remanufacturing operation. Transit operators who perform adequately will be designated by Engelhard as ''probational'' remanufacturing sites. This facility will then be required to maintain records of all critical measurements of remanufactured camshafts, blowers, and/or turbochargers. These records will be inspected periodically by Engelhard. Upon completion of at least two Engelhard periodic reviews without any problems, the facility may be upgraded to an ''Engelhard Certified Remanufacturer''. This option provides EPA with reasonable assurance that the 0.10 g/bhp-hr PM standard will be achieved, while providing transit operators with reasonable sourcing flexibility.

Engelhard is required to provide a 100,000 mile defect warranty and 150,000 mile emissions performance warranty for the ETX kit and all of its components regardless of which of the three approved supply options is used. Furthermore, EPA has authority to conduct in-use testing of certified equipment to determine compliance with the requirements of the program.

As noted above, EPA is certifying option 2 and 3 to increase transit operator flexibility. The option 3 Engelhard Certified Remanufacturer Program is to be administered by Engelhard without further explicit involvement of EPA. As with any certification, if EPA determines that any supply option is not resulting in a certified engine configuration, then EPA has the authority pursuant to 40 CFR section 85.1413. Transit operator responsibilities are described in more detail in Section IV of today's Federal Register notice.

The ETX equipment is certified to a PM emission level of 0.10 g/bhp-hr for all 1979 through 1989 DDC 6V92TA MUI urban bus engines using either diesel fuel #1 or #2 (excluding those originally certified as meeting California emissions standards). Table C lists the applicable engine models and certification levels associated with the certification announced in today's Federal Register.

TABLE C.—CERTIFICATION LEVELS

Engine models	Engine code	Certified PM level
1979–1989 Detroit diesel 6V92TA MUI.	all (excluding those originally certified as meeting California emissions standards)	0.10 (g/bhp-hr)

II. Summary and Analysis of Comments

Comments were received from nine parties in response to the Federal Register notice (61 FR 50549, May 6, 1996). Commenters include Detroit Diesel Corporation (an engine manufacturer), Johnson Matthey (an equipment manufacturer), and several transit properties including Milwaukee County Transit System (Milwaukee County), Long Beach Transit, New York City Transit (NY MTA), New Jersey Transit (NJ Transit), Kansas City Area Transportation Authority (KCATA), Connecticut Transit (CT Transit), and Dallas Area Rapid Transit (DART).

Comments generally fell into the following categories: kit applicability, maintenance, fuel economy, ability of the equipment to meet the 0.10 g/bhp-hr standard, backpressure, durability, toxic emissions, part sourcing, and supply options. Comments outside of these categories were also received, and are discussed separately below.

In general, transit fleets commenting on this equipment are concerned with fuel economy impacts, part sourcing, and equipment cost. DDC, as the original manufacturer of the engines to which this equipment is intended, noted it's desire to ensure that certification of this equipment would not negatively impact the reliability, durability, performance, or fuel economy of its engines, or in any way damage their product reputation or relationship with their customers. EPA appreciates the extensive comments provided by DDC, which are discussed in more detail below. JMI also provided extensive comments related to this equipment. Most significant are JMI's concerns that the technology of spray coating components is unproven, and that Engelhard's proposed supply options may present barriers to competition. JMI's complete comments are also discussed in detail below.

a. Ability of the Kit to Meet 0.10 g/bhp-hr

EPA received detailed comments from DDC regarding the ability of the ETX to meet the 0.10 g/bhp-hr PM standard. DDC performed Federal transient emissions testing of the ETX kit in various configurations. In addition, two transits, Long Beach and DART, raised question regarding the ability of the ETX to consistently achieve the 0.10 g/bhp-hr level to which Engelhard requests certification.

DDC performed testing on each of the three HP ratings described by Engelhard in its original notification. In addition, DDC performed testing to determine the relative PM reductions associated with catalyst alone versus the entire ETX kit. DDC was unable to demonstrate PM emissions at or below the 0.10 g/bhp-hr level on any of their tests, and suggested that additional verification of emission reductions be obtained prior to certification. In addition, DDC stated that it had experience with components using ceramic coatings, noting they have seen little, if any, benefits associated with the use of such coatings. DDC requested that EPA quantify the reductions associated with each facet of the ETX kit prior to certifying the equipment. The issues raised by DDC are discussed below.

Regarding DDC's comments on the ability of the ETX kit to achieve 0.10 g/bhp-hr, no explanation was provided by DDC for the difference in test results between it's testing and Engelhard's testing. DDC and Engelhard together reviewed test procedures, engine condition, parts condition, etc., and could not agree on why the test results differed.

However, subsequent additional review by Engelhard revealed differences that Engelhard believes could potentially impact emission results. As described in a September 12, 1996 letter to EPA, prior to performing it's original certification test, Engelhard performed a 100-hour break-in on the test engine to ensure proper and adequate seating of the piston rings and to stabilize emissions results. DDC, in it's testing of the ETX kit, performed only 25 hours of engine break-in. According to its July 18, 1996 comments, DDC believes that 25 hours is sufficient to stabilize emission results for these engines. Engelhard, however, pointed out that measured engine motoring losses at rated speed for the DDC testing was 280 Newton-meter (Nm), versus 250 Nm for the Engelhard testing, implying that the DDC test engine experienced more internal frictional loss compared to the Engelhard engine. Engelhard believes that the higher frictional loss measured by DDC resulted from insufficient break-in, and could explain the higher PM emissions measured by DDC.

In a November 22, 1996 letter to EPA, DDC explained that the 280 Nm motoring loss was from the DDC's testing of the 253 HP version of the ETX kit, whereas the 250 Nm obtained in Engelhard's testing was from the 294 HP version of the ETX kit. DDC states that when it tested the 294 HP version, the motoring loss was 274 Nm. DDC's published specification for running loss on the 294 HP version 6V92TA MUI is 268 Nm. DDC believes that the measured motoring loss (274 Nm) is not unusually high, but rather, Engelhard's measured loss is unusually low. DDC believes that use of SAE30W lubrication oil, rather than the DDC-specified SAE40W, may account for this difference.

Engelhard also noted that DDC performed testing at a measured exhaust backpressure of 11.9 kPa (3.5 inches Hg.) compared to 6.77 kPa (2.0″ Hg.) for Engelhard's January 26, 1996 test. General industry practice is to test engines at 80 percent of manufacturer's recommended maximum backpressure at rated speed. The test engine specification for maximum recommended backpressure is 2.4″ Hg., resulting in a backpressure setting for testing of 2.0″ Hg. DDC claims to have been unable to achieve the 2.0″ Hg. setting, stating the catalyst unit itself imposed a backpressure of 2.9″ Hg. In its November 22, 1996 letter to EPA, DDC noted a difference between the catalyst Engelhard used in its certification testing and the catalyst

Engelhard provided to DDC for their testing. DDC contends that Engelhard's certification testing was conducted with a simple flow-through catalyst, rather than a catalytic muffler, as utilized in DDC's testing. DDC believes that the backpressure of a catalytic muffler is greater than that of a simple flow-through catalyst, thus explaining DDC's inability to obtain the 2.0″ Hg. backpressure specification.

An October 17, 1996 conversation with Engelhard revealed that the catalyst utilized by Engelhard in its certification testing had to be modified, due to dynamometer interference, in order to be properly installed in the test cell. Such modification was not necessary for proper installation into DDC's test cell. Engelhard contends that the incremental backpressure associated with the muffler portion of the CMX–5 is minimal compared to the backpressure associated with the catalyst portion of the unit. Engelhard conducted additional hot-start FTP tests to demonstrate the impact of increased backpressure on the ability of the ETX kit to achieve the 0.10 g/bhp-hr standard. Two FTP transient FTP tests were conducted at 3.0″ Hg. and one at 4.5″ Hg. As discussed in a November 24, 1996 letter from Engelhard to EPA, in each case, PM results were below 0.10 g/bhp-hr, and were very close to Engelhard's original and secondary certification test results. Emissions of HC, CO and NO_X remained below Federal standards. Based on this additional testing, EPA believes that the catalyst configuration difference and potential difference in backpressure does not explain the difference in PM results obtained by Engelhard and DDC.

In a September 4, 1996 letter to EPA, Engelhard noted another difference between it's testing and DDC's is the fuel injectors. Engelhard's test engine used injectors which fall into the DDC-designated category of ''premium'' Reliabuilt injectors. Engelhard states that fuel flow variances among premium injectors are less variable than on non-premium Reliabuilt injectors. The injectors used by DDC, although consistent with the part number identified by Engelhard, did not fall into this same category. At the time of Engelhard's original ETX certification test of January 26, 1996, Engelhard was unaware that the fuel injectors used in their test engine were ''premium''. Only after attempting to resolve the testing differences with DDC did Engelhard become aware of this fact. Engelhard believes the more consistent fuel distribution associated with premium injectors could impact emissions, and could account for some or all of the difference in measured emissions between Engelhard and DDC. As a result, Engelhard has specified the use of premium matched fuel injectors to be used with the ETX kit. In telephone follow-up with DDC on December 6, 1996, DDC stated that premium Reliabuilt injectors contain more new parts, and fewer remanufactured or used parts, compared to non-premium Reliabuilt injectors. DDC believes the emissions performance of Reliabuilt premium injectors is equivalent to the emissions performance of non-premium injectors, but acknowledges that premium injectors may demonstrate superior in-use durability due to the higher percentage of new parts in the injector.

In spite of the differences noted by Engelhard between it's testing and DDC's testing, EPA believed that additional data were necessary in order to address the uncertainty raised by DDC's comments. To that end, EPA requested that Engelhard retest the ETX kit in the presence of an EPA test observer. This course of action is consistent with DDC's recommendation in its comments that EPA pursue ''additional verification'' of the ETX kit.

On September 27, 1996, Engelhard performed a secondary ETX certification test at SouthWest Research Institute, in San Antonio, TX.[1] The results of this testing indicate that the ETX kit can achieve the 0.10 g/bhp-hr PM level. The EPA observer found no testing or procedural violations. According to DDC, two days prior to EPA's visit, a DDC representative observed testing of the Engelhard equipment at the same facility, and likewise found no indication of testing concerns.

In addition to conducting the above-noted additional test in the presence of an EPA observer, Engelhard provided additional hot-start transient test data in its September 4, 1996 letter (both with and without coated exhaust components) that supports the consistent ability of the ETX kit to meet the 0.10 g/bhp-hr standard.

In summary, EPA believes that Engelhard has sufficiently demonstrated the ability of the ETX kit to achieve the 0.10 g/bhp-hr PM standard. Although there is no clear explanation for the difference in test results between Engelhard's testing and DDC's testing, EPA believes Engelhard has provided sufficient supplemental data which demonstrates the ability of the ETX kit to achieve the 0.10 g/bhp-hr PM standard. EPA retains authority to conduct in-use testing of certified equipment as described in 40 CFR Subpart O. In addition, equipment manufacturers must provide a 100,000 mile defect warranty, and a 150,000 mile emission performance warranty on certified equipment.

Regarding DDC's suggestion that Engelhard quantify the relative PM benefits associated with different aspects of the kit, EPA notes that no such requirement exists in the certification requirements of this program. EPA has in the past expressed its position that components that do not contribute to the ability of equipment to reduce emissions, or which are not reasonably necessary to provide the equipment manufacturer with adequate liability protection, will not be considered part of a certified equipment package. DDC comments that, based on it's past experience, the coatings used by Engelhard in this kit may not contribute to any PM reductions. However, DDC has not provided any evidence that coatings which DDC has evaluated are the same, or similar to, the GPX–5m coating of this equipment package. In fact, Engelhard provided EPA with a confidential description of the coating and it's application technique, that support Engelhard's claim that the coating composition has changed over time, and likely contributes to PM reduction. Without a clear indication that the current GPX–5m coating does not contribute to PM reduction, EPA believes it reasonable for Engelhard to include such coating as an emissions-related part of the ETX kit.

b. Equipment Durability

Several commenters raised questions with regard to the durability of the ETX kit, or its components, in actual use. NY MTA comments that operating experience with the ETX kit is limited, and questions the performance characteristics of the ETX kit on in-service buses. Long Beach commented that there is no information to substantiate that this equipment will effectively provide an average engine life of 300,000 miles after rebuild. KCTA stated that it has had an unfavorable experience with previous generation ceramic engine coatings. KCTA has used GPX coatings on three buses in the past. One bus is still in service (after 2½

[1] As discussed elsewhere in today's notice, in response to EPA and public comments, Engelhard had modified the ETX kit by removing coated exhaust components from the kit, and returning the injector height and throttle delay settings to their original specifications. The testing performed on September 27, 1996 served three purposes; 1) to address DDC's test data regarding the ability of the kit to achieve 0.10 g/bhp-hr; 2) to ensure that the 0.10 g/bhp-hr level could be achieved in spite of the removal of the coated exhaust components and resetting of injector height and throttle delay; and 3) to provide additional data to be used for determining the fuel economy impact of the ETX kit.

years of operation), a second bus lasted only 5 months, and a third lasted only 10 months. No details were provided by KCTA explaining the reason these buses were removed from service. KCTA recommends additional testing of ceramic coatings prior to certification. NJ Transit expressed concern that degradation of the proprietary spray coating could leave them open to non-compliance penalties should an engine equipped with the ETX kit fail to meet emissions standards in-use.

DDC provided several comments regarding durability. First, DDC states that new engine manufacturers are required to conduct durability testing for new engine certification. DDC acknowledges that the urban bus retrofit/rebuild regulations do not require such testing, but expressed concern whether emissions would remain below the standard throughout the life of the rebuild. In addition, DDC states that some oxidation catalyst formulations can suffer from poisoning through contact with exhaust gases, and states that no data have been presented which shows this particular catalyst formulation is resistant to poisoning. Finally, DDC comments that its experience with ceramic coatings indicates that they can become overlaid with combustion deposits, reducing their efficiency. However, DDC also states that they have no reason to believe that thermal barrier coatings do not retain their thermal insulating properties over time.

JMI also provided several comments regarding durability. First, JMI states that ceramic spray coatings are unproven technologies in diesel engines. JMI expressed concern that surface contaminants, such as oil, on both new and rebuilt parts may interfere with proper adhesion of the coating material to the coated engine part. In addition, JMI referenced a report prepared for the National Aeronautics and Space Administration (NASA) and U.S. Department of Energy (DOE) which concludes that ''(r)eliability and durability of thermal barrier coatings remain major issues''.

EPA appreciates that transit operators are concerned with the durability of this equipment, and subsequent additional costs or engine damage that potentially could result from premature equipment failure. EPA is also concerned, in general, with durability of equipment certified under this program because of the potential impacts on emissions. However, EPA notes that the urban bus retrofit/rebuild regulations do not require an in-service durability demonstration as a condition of certification, nor is certified equipment required to be durable for 300,000 miles. Rather, equipment certifiers, including Engelhard, are required pursuant to 40 CFR Section 85.1409 to provide a 100,000 mile equipment defect warranty and a 150,000 mile emissions performance warranty.

KCTA's limited experience with ceramic coated engine parts resulted unfavorably. Unfortunately, KCTA's comments do not correlate the early removal from service of the two KCTA buses with the use of previous generation ceramic coated engine components. Nonetheless, these comments raise a legitimate concern regarding durability—a concern also raised by DDC and JMI in their comments, which EPA addresses below.

Regarding catalyst poisoning raised by DDC, EPA has no reason to believe, nor did DDC provide a reason to suspect, that the catalyst formulation used in this kit will suffer from exhaust gas poisoning. Engelhard's previously certified CMX catalytic converter (60 FR 28402, May 31, 1995) has been in use in the retrofit/rebuild program for over a year, during which time which EPA has not become aware of any incidents of catalyst poisoning. The catalyst in the ETX kit is an improved version of the CMX. EPA will continue to monitor problems with this, or other, certified equipment, and encourages transit operators to provide any information regarding catalyst poisoning.

JMI bases its comments regarding the viability of spray coatings primarily on the conclusions reached in the NASA/DOE report prepared in 1991. However, EPA cannot rely on the JMI comments as a basis to deny certification because JMI has provided no information to suggest the coating technology analyzed in the NASA/DOE report is the same as, or similar to, the GPX–5m coating used in the ETX equipment package. In fact, Engelhard's confidential description of the ceramic coating and it's application technique provided to EPA, highlights differences between the coatings examined in the NASA/DOE study compared to the coating Engelhard has developed for the ETX kit. The NASA/DOE findings of 1991 indicate that, at that time, additional development of coatings may have been necessary to make coating technology viable in the diesel engine market place. According to the confidential information provided by Engelhard, the ceramic coating technology has developed compared to that examined in the NASA/DOE study.

EPA has previously certified an Engelhard equipment package utilizing GPX coatings (60 FR 47170, September 11, 1995). From the standpoint of physical durability of the coating, EPA is not aware of any premature wear or failure of this certified equipment. As mentioned previously, in response to concerns about the physical durability of the new GPX–5m coating, Engelhard provided EPA a detailed confidential description of the coating and its application technique. In addition, in a May 23, 1996 letter to EPA, Engelhard provided data from three in-use buses using previous generation GPX–4 coatings. Coating thickness measurements were made on piston crowns and cylinder head combustion chambers, and were found to be within nominal design specifications at an average of 123,000 miles. In addition, deposit formations on the combustion surfaces were nearly non-existent. Engelhard indicates that design advances in the current GPX–5m coatings are intended to further reduce deposit formation and increase coating durability beyond that of the GPX–4 coating.

EPA is concerned, in general, with equipment durability, and believes that certifiers will evaluate the durability of their equipment in order to minimize their liability resulting from the emissions performance warranty. However, program regulations do not require a durability demonstration. EPA believes the available information does not indicate a durability concern with the equipment certified in today's notice, and therefore, does not provide sufficient basis to deny certification on these grounds. EPA retains authority to conduct in-use testing of any certified equipment for compliance with the requirements of the program. In addition, equipment certifiers must provide a 100,000 mile defect warranty and a 150,000 mile emissions performance warranty on all certified equipment.

Lastly, regarding NJ Transit's concern for being subject to penalties if degraded coatings cause an engine to fail to meet its certified PM level, EPA notes that the equipment certifier is responsible for the emissions performance of the engine through the 150,000 mile emissions performance warranty period, if the transit properly installs and maintains equipment in accordance with the equipment manufacturer's instructions. The transit operator is responsible for proper installation and use of certified equipment, and is responsible for the emissions performance of equipment operated beyond the 150,000 miles emissions warranty period. Also, the retrofit/rebuild program does not obviate compliance with any state or local emission requirements, such as inspection/maintenance (I/M) or smoke testing programs.

c. Exhaust Backpressure

DDC provided comments related to the exhaust backpressure resulting from installation of the CMX–5 catalytic muffler, and its potential impact on engine performance and durability. DDC provided these comments in response to the proposed certification, and in a November 22, 1996 letter to EPA.

DDC notes that the maximum recommended exhaust backpressure for 6V92TA MUI engines generally ranges from 2.5″ Hg. to 3.5″ Hg. at full rated power, with the majority of engines having a backpressure specification between 3.0″ Hg. and 3.5″ Hg. DDC is concerned that the backpressure imposed by the CMX–5 catalyst may cause engines to exceed the maximum exhaust backpressure specification recommended by DDC. DDC references chassis dynamometer testing performed on several engines utilizing the original CMX version catalytic muffler produced by Engelhard and certified by EPA under this program. DDC comments that the chassis testing shows average backpressure at rated speed and full load of 5.3″ Hg. with the CMX installed, versus 3.3″ Hg. with the standard exhaust muffler installed. Finally, DDC expressed its opposition to the procedure recommended by Engelhard for determining whether the catalyst unit requires cleaning. Engelhard's instructions involve operating the engine in a rated speed, no load condition (high idle) and recording the pressure drop across the CMX–5 unit. This is the same procedure recommended by Engelhard for determining backpressure across the original CMX catalytic muffler, and was derived from DDC Service Information Bulletin 7–D–95. DDC, however, contends that this service procedure was only intended for a limited population of 6V92TA engines that were originally equipped with particulate traps. Pursuant to an agreement with EPA, these traps were removed and replaced with catalytic converter-mufflers because of severe durability concerns.

The chassis dynamometer data provided by DDC were generated on buses operated by a fleet located in the Northeast. The Agency's follow-up conversations with that fleet indicate that a venturi was improperly installed when measuring the backpressure, resulting in unusually high backpressure readings with the CMX installed. With the measurement conducted properly, exhaust backpressure was 3.2″ Hg., which is below the recommended maximum backpressure for those engines. Therefore, EPA does not believe that DDC's comments with respect to measured in-use backpressure are convincing.

EPA does not dispute that a catalytic muffler, in general, may increase the engine exhaust backpressure compared to a standard noise muffler. In fact, when the ''secondary'' ETX certification test was conducted, EPA requested a backpressure comparison between a standard muffler and the CMX–5. EPA selected the standard muffler, and Engelhard measured the incremental difference between the muffler and the CMX–5 at rated speed and full load. The test revealed a 0.6 inches Hg. difference in backpressure (2.0 inches Hg. with the muffler installed versus 2.6 inches Hg. with the CMX–5 installed). The previously-certified CMX has been in service for over a year, and EPA has not become aware of any problems relating to or resulting from increased backpressure. During a December 17, 1996 conversation, representatives of the Washington Metropolitan Area Transit Agency (WMATA) stated they have not seen any discernable difference in backpressure or fuel economy associated with use of Engelhard's previously certified CMX catalyst. In a December 2, 1996 letter to EPA, Engelhard provided data demonstrating that the backpressure resulting from the CMX–5 unit is equal to, or lower than, the backpressure resulting from the certified CMX over a wide range of exhaust flow rates. Finally, DDC has provided no explanation of the difference, in terms of susceptibility to backpressure impacts, between the engines for which Service Information Bulletin 7–D–95 was intended, and those which are covered by this, and other, retrofit certifications utilizing catalytic mufflers.

Any future information provided by interested parties regarding the impacts of certified equipment on exhaust backpressure would be taken under consideration. EPA appreciates that there may room for improvement in maintenance procedures of equipment certified under this program. Such concerns, in general, can also occur with procedures relating to new engines. EPA encourages all equipment certifiers to issue revised check procedures when appropriate. If Engelhard determines that another check is appropriate, or if EPA becomes aware that backpressure is exceeding manufacturer limits on in-use buses, then Engelhard should revise such procedures. Pursuant to 40 CFR Section 85.1413, EPA has authority to decertify equipment that does not comply with the requirements of the regulations.

d. Supply Options

As originally proposed in an addendum dated March 25, 1996, three supply options would be available at Engelhard's discretion. Under proposed option 1, Engelhard would supply all components of the kit (GPX coated parts, CMX–5 converter muffler and all new and rebuilt parts specified in Attachment 1 of the notification of intent to certify) to the transit operator. Under option 2, Engelhard would supply the GPX coated components (exhaust manifolds, turbocharger Y-pipes, cylinder kits, and cylinder heads) and the CMX–5 converter muffler. The other engine components (fuel injectors, camshafts, air inlet hose, blower, blower drive gear, blower bypass valve, turbocharger, turbocharger Y-pipe, exhaust manifolds, and gasket kit) would be purchased separately or supplied separately as long as such parts were Engelhard OEM specified components or their equivalent. Under option 3, Engelhard would provide the GPX coated parts described in option 2 above, as well as the CMX–5 converter muffler, and the new engine parts listed in Attachment 1 of the notification of intent to certify (gasket kit, cylinder kits, air inlet hose, and blower bypass valve). The remanufactured parts required to complete the kit (fuel injectors, camshafts, blower, blower drive gear, turbocharger, exhaust manifolds, and turbocharger Y-pipe) would be rebuilt in-house by the transit operator if the transit operator was deemed an ''Engelhard Certified Remanufacturer''. To obtain this status, transit operators or third parties would be required to undergo training from Engelhard, and be certified by Engelhard as capable of remanufacturing components within required tolerances. In addition, transit operators would be required to maintain records to demonstrate continued ability to meet these requirements.

With regard to option 2 proposed by Engelhard, DDC commented that allowing the use of ''equivalent'' parts is not appropriate. DDC, as the original engine manufacturer to which this applies, has developed products over many years which encompass a myriad of subtle design features intended to ensure proper engine function, performance, and durability. DDC does not make it's specifications publicly available, and therefore, believes Engelhard is not qualified to determine ''equivalency'' of parts. DDC notes that the certification tests conducted by Engelhard utilized DDC engine parts. DDC believes that additional tests on specific non-OE parts should be required if these parts are eligible for use in this kit.

DDC's comments regarding supply option 3 are similar to those described above. DDC does not believe that Engelhard can provide transit operators with the appropriate specifications, tolerances, and quality control procedures to which a transit operator must rebuild in order to become a Certified Engelhard Remanufactured. Finally, DDC comments that each supply option proposed by Engelhard should be evaluated separately for it's impact on life cycle cost.

JMI provided substantial comments regarding the proposed supply options. Regarding option 1, JMI commented that Engelhard should be required to disclose the allowable sources and specification of ''equivalent'' parts. JMI comments that coatings for engine parts will be provided by Engelhard's wholly owned technology division. JMI believes that EPA must account for the possibility of interrupted availability of coated components resulting from such interruptions as union problems, divesture, natural disaster, etc.

Regarding option 2, JMI commented that it is beyond Engelhard's legal authority to create a qualified vendor list on behalf of a public transit agency, and that doing so would create a conflict of interest. KCTA mirrored this concern stating that the various supply options allow Engelhard to dictate parts choice of transit operators. In addition, JMI believes that allowing Engelhard discretion to choose which supply options will be made available represents a restraint of trade.

Lastly, JMI comments that Engelhard's proposed supply options will result in labor problems for transit operators who may be forced to eliminate or close their repair operations.

EPA, in general, shares many of the concerns noted by commenters regarding supply of the ETX kit. EPA believes that Engelhard, in proposing a flexible kit distribution plan, attempts to avoid many of the issues raised by commenters. However, EPA must be assured that any increase in flexibility does not undermine emissions reductions expected from certification of equipment. In order to resolve the extensive comments surrounding the proposed supply options, significant follow-up activity was pursued by EPA, as described below.

EPA fundamentally agrees with DDC that certification should be limited to that equipment which has been demonstrated to achieve the claimed certification level. In this case, Engelhard conducted all testing of the ETX kit using DDC engine parts in conjunction with the Engelhard catalytic converter and coatings. Engelhard provided no demonstration or other assurances, other than it's required commitment to honor the urban bus warranties, that ''equivalent'' engine parts would result in PM emissions of 0.10 g/bhp-hr or less. EPA does not dispute the possibility that certain non-DDC parts may provide equivalent function, performance, and/or emissions characteristics as the DDC parts used in Engelhard's certification testing. However, none of these parts were tested, nor was any engineering argument made by Engelhard to indicate equivalent performance. In the absence of emissions data or technical argument relating to the characteristics or design features of OEM and non-OEM parts that affect emissions performance, EPA has no basis for certification of the Engelhard equipment when an engine is rebuilt using parts other than those which Engelhard has demonstrated will achieve the stated emissions level.

EPA also agrees with JMI that, at a minimum, identification of allowable equivalent parts and the means by which this equivalency was determined is required in order to determine if such parts are potentially capable of achieving the claimed reductions.

In an August 23, 1996 letter, EPA requested that Engelhard provide a listing of specific brands and part numbers which Engelhard determined to be ''equivalent'', and the means by which Engelhard determined this equivalency. In addition, EPA requested clarification as to what specifications Engelhard would provide a transit operator who wished to become a Certified Engelhard Remanufacturer and continue to rebuild engines in-house.

In its September 4, 1996 response to EPA's request, Engelhard was unable to identify specific brands or part numbers which it believed to be ''equivalent'' to the DDC parts used in the certification testing. Engelhard will supply only DDC parts for those parts supplied under option 1. Under option 2, Engelhard specifies only DDC parts, which fleets can obtain through normal supply channels rather than from Engelhard, thus providing fleets with part sourcing flexibility while maintaining reasonable assurance that the claimed PM level is achieved. Therefore, under both option 1 and option 2, transit operators must use the specified DDC parts in conjunction with the remaining ETX kit components, as demonstrated by Engelhard to be capable of achieving the 0.10 g/bhp-hr PM level. The practical difference between these two options is that under option 2 the fleet has flexibility to obtain DDC parts through it's normal channels, while option 1 requires purchase of all parts from Engelhard. Manufacturers of ''equivalent'' aftermarket parts may choose to certify their parts for use in the ETX kit in a separate proceeding subject to testing and certain warranty concerns.

Regarding the option 3 Engelhard Certified Remanufacturer program, EPA supports the notion of fleets maintaining the ability to remanufacture and rebuild certain components in-house. Outside of the clear requirement to technology demonstrated to reduce PM exhaust emissions, the Urban Bus Retrofit/Rebuild Program was not intended to significantly impact current fleet rebuilding practices. With regard to the 25 percent PM reduction standard, transit operators currently have flexibility to choose add-on reduction equipment, thus allowing continued in-house rebuilding of engines and components. On the other hand, if EPA were to certify a trigger of the 0.10 g/bhp-hr PM standard that did not allow for continued rebuild of components in-house, and if this were the only equipment available to meet the 0.10 g/bhp-hr standard, then certain transits would be required to cease rebuilding these components or risk being in violation of program requirements.

EPA believes it reasonable to allow in-house rebuild of certain components by transit operators utilizing the ETX kit, under certain conditions. First, in-house rebuilding is limited to camshafts, blowers, and turbochargers. EPA believes that allowing rebuild of other components, such as fuel injectors, cylinder liners and cylinder heads, would raise substantial concerns whether the resulting engine could meet the 0.10 g/bhp-hr standard because of their key role in oil and fuel control of the engine. Allowing in-house rebuild of camshafts, blowers and turbochargers introduces some uncertainty with respect to the PM emissions performance of the resulting engine because of their role in controlling combustion air flow within the engine. However, EPA imposes the following measures to mitigate this uncertainty. First, Engelhard must specify, and fleets must rebuild to, the relevant DDC camshaft, blower and turbocharger part number utilized in the certification test engine. Second, Engelhard will implement it's Engelhard Certified Remanufacturer program for any and all fleets affected by the Urban Bus Retrofit/Rebuild Program choosing to rebuild these components in-house. This parts supply option necessitates that participating fleets undergo periodic quality checks, performed by Engelhard, of components rebuilt in-house. Unsatisfactory performance would result in the fleet losing, or not achieving, the status of Engelhard Certified Remanufacturer, and subsequently losing the option to rebuild these components in-house. Engelhard provides the defect and emissions performance warranties required pursuant to 40 CFR 85.1409 for engines using components rebuilt by Engelhard Certified Remanufacturers.

EPA has been informed that the ability to continue some level of in-house rebuilding is important to the needs of transit operators. The Engelhard Certified Remanufacturer program, combined with the limited set of components that can be rebuilt in-house, result in increased flexibility for transit operators yet allow EPA to maintain reasonable assurance concerning PM reduction.

Regarding DDC's comment that each supply option be evaluated separately for it's impact on life cycle costs, EPA believes this is unnecessary. EPA has determined that supply option 1—the option in which Engelhard supplies all necessary components of the kit—complies with the life cycle cost requirements of the Urban Bus Retrofit/Rebuild Program, as described below. At a minimum, this supply option must be provided to any and all transit operators. Therefore, certification of this supply option ''triggers'' the 0.10 g/bhp-hr standard. Use of the other two supply options is strictly voluntary, and any cost savings or added costs are accepted voluntarily by the fleet operator.

f. Life Cycle Cost

Section 1403(b)(1)(ii) describes those items which must be considered when analyzing life cycle cost of equipment, including equipment purchase price, incremental fuel cost/savings, installation costs, maintenance costs, and other costs specific to fuel additives and fuel conversions. Most commenters provided input on at least one cost-sensitive topic area. Comments received are described below, and are grouped by general topic area within the larger context of life cycle costs.

i. Maintenance Cost

NY MTA, NJ Transit, and CT Transit each expressed concern that Engelhard did not include any allowance in the life cycle cost analysis for maintenance of the equipment. EPA believes that the engine upgrade portion of this equipment requires no additional maintenance incremental to that required on a standard rebuild. In addition, the coated component portion of the kit cannot be serviced because the coated parts are internal to the engine. Therefore, no additional maintenance is expected related to the coated components. EPA believes any concerns related to incremental maintenance would apply only to the catalyst unit.

Engelhard maintains that the CMX–5 catalyst unit is maintenance-free over the emissions performance warranty period of 150,000 miles, and notes that the currently certified CMX has been in operation for over a year. During this time neither Engelhard nor EPA has become aware of any additional maintenance required to keep the unit functional, when the engine is maintained in accordance with instructions. Engelhard stated that several CMX catalysts which have accumulated over 150,000 miles without maintenance have been inspected and found to be functioning properly. EPA questioned Engelhard regarding the prescribed catalyst cleaning procedure, and the need for such a procedure if the unit is truly maintenance free. Engelhard responded that an improperly operating or improperly tuned engine could lead to clogging of the catalyst unit. To the extent this happens, transit operators must have instructions for cleaning the unit. Routine cleaning of the catalyst unit on properly tuned engines is not required, and thus no life cycle cost is associated with this cleaning procedure. Therefore, EPA has determined that no additional maintenance costs, incremental to costs associated with a standard rebuild, are associated with the use of this equipment.

ii. Incremental Fuel Cost

EPA received numerous comments regarding the fuel economy impact of the ETX kit. DDC's testing of the ETX kit showed a brake-specific fuel consumption (BSFC) ranging from 0.469 to 0.472 lbs./bhp-hr. DDC believes that comparing these BSFC measurements with Engelhard's original 1979 and supplementary 1986 baseline tests (0.421 and 0.442 lbs./bhp-hr) may not be appropriate given that DDC and Engelhard testing were conducted at different laboratories which may use different test procedures and equipment. However, DDC believes that comparing it's BSFC data for the ETX kit to a 1979 6V92TA baseline engine tested by DDC recently in its own retrofit certification program (60 FR 51472, October 2, 1995) is valid. Comparison of the original ETX certification test with DDC's baseline testing shows an average 2.2 percent fuel economy penalty for the ETX kit. In its November 11, 1996 and November 22, 1996 follow-up letters to EPA, DDC notes other factors, such as blower drive ratio and catalyst backpressure, which are consistent with increased fuel consumption with the ETX kit. Considering these qualitative factors, combined with its test data, DDC believes that a 2–4 percent fuel penalty is appropriate.

JMI commented that a four percent fuel economy penalty, as demonstrated by Engelhard's original certification and baseline test data, should be used to assess the fuel economy impact of the ETX kit. In addition, JMI referenced a report prepared for the National Aeronautics and Space Administration (NASA) for the U.S. Department of Energy, which concludes that thermal barrier coatings on diesel engine combustion components can result in up to a two percent fuel economy penalty compared to baseline ''metal'' (i.e., non-coated) components. EPA notes that the relevancy of this report to this particular certification is unclear.

Milwaukee County, Long Beach Transit, CT Transit, NJ Transit, and NY MTA all commented regarding the fuel economy impacts associated with the ETX kit. In general, these transits believe that the Federal transient test procedure does not represent real-world urban bus operation, and therefore, the actual fuel economy impact is unknown. One commenter suggested that fuel economy impact be determined through testing over the Advanced Design Bus Cycle chassis dynamometer test, which the commenter believed to be more representative of urban bus operation.

Regarding the comments from transit operators, 40 CFR 85.1407(a)(3)(ii) states, in part, that certifiers must include in their notification of intent to certify ''(t)he percent change in fuel economy * * * based on testing performed over the heavy-duty engine Federal test procedure or an approved alternative test procedure''. Engelhard complied with this requirement by providing the percent change in fuel economy resulting from use of this kit as measured over the heavy-duty engine Federal test procedure described at 40 CFR Part 86 Subpart N. While test data generated using the Advanced Design Bus Cycle could be useful to EPA when determining fuel economy impacts, it is not required. In addition, in order to demonstrate compliance with the 0.10 g/bhp-hr PM standard, testing must be conducted using the engine-based Federal test procedure. Requiring additional testing to demonstrate fuel economy on a chassis-based test cycle would be an expense of unknown benefit.

Regarding DDC and JMI comments, the following describes the available data on the subject. Table D below summarizes the available transient BSFC data for both baseline engines and engines with the ETX kit.

TABLE D.—AVAILABLE BASELINE AND ETX TEST DATA

Test description	Test date	BSFC[1] (lbs./bhp-hr)
Engelhard's original 1979 baseline	March 1, 1996	0.421
Engelhard's original ETX certification test	January 26, 1996	0.438
Engelhard's supplementary 1986 baseline	October 4, 1996	0.442
Engelhard's supplementary ETX certification test	September 27, 1996	0.447
DDC's 1979 baseline	NA	0.461
DDC's ETX test average	June/July 1996	0.471

Brake-specific fuel consumption measured in units of pounds per brake horsepower-hour.

In it's original application for certification, Engelhard claimed no fuel economy penalty associated with the ETX kit, even though Engelhard's original certification data for the ETX configuration indicate a 4 percent fuel economy penalty compared to a standard 1979 6V92TA MUI baseline rebuild.

In a March 8, 1996 letter to EPA, Engelhard further explained its rationale for the claim of no fuel economy impact, noting that the cylinder liners (part number 8923348) used in the 1979 baseline rebuild have larger inlet ports compared to those currently available for rebuilding engines, thus improving volumetric efficiency of the engine. Such an improvement in volumetric efficiency, Engelhard claims, would lead to improved fuel economy compared to an engine with lower volumetric efficiency. In addition, Engelhard claims that the 1979 liner used to rebuild the original baseline test engine allows more oil into the combustion chamber, causing an increase in PM, but also an improvement in fuel economy compared to cylinder kits with a smaller inlet port. Engelhard provided data showing a PM oil fraction for the 1979 baseline test of 0.076 g/bhp-hr, compared to 0.046 g/bhp-hr for the January 26, 1996 ETX certification test.

In addition, Engelhard argues that the 4 percent demonstrated on the original 1979 baseline is reasonably close to the plus/minus 3 percent variability of the fuel economy measurement. This is supported by the supplemental baseline testing conducted on October 7, 1996 on an engine rebuilt to a 1986 6V92TA MUI configuration. The fuel consumption data for this test is shown in Table D above, and shows virtually no fuel economy impact (about 1 percent) compared to the ETX configuration.

In its November 11, 1996 letter, DDC refutes Engelhard's claim that the larger port in the 1979 configuration improves the fuel economy relative to a smaller ported liner. DDC states that the liner port is dimensioned such that the bottom of the port remains constant in the liner, with the top of the port being higher in larger port sizes. In DDC's opinion, port size has a relatively small impact on fuel economy compared to factors such as engine exhaust backpressure and blower drive ratio. In addition, DDC notes that the liner used in Engelhard's original 1979 baseline test engine had 0.95 inch ports, which are still readily available today. EPA recognizes that fuel economy may vary from test to test depending on several factors including base engine design and measurement technique. The statistical determination of the variability of this combination would require additional testing and is beyond the practical requirements of the Urban Bus Program. EPA, therefore, makes the following decision on the impact of fuel economy on life cycle costs based on the available data. EPA believes the most reasonable approach, based on the available data, is to average the fuel economy impacts demonstrated by Engelhard on its 1979 and 1986 rebuild configurations (about 1 percent and four percent, respectively), resulting in a fuel economy penalty of about 2 percent. This figure is consistent with that demonstrated by DDC (about 2 percent), and other qualitative statements made by JMI and DDC. Using this 2 percent figure and the equations of Section 85.1403 of the program regulations, EPA determines the fuel economy impact associated with the ETX rebuild kit to be $563.36 (in 1992 dollars), or $635.64 (in October 1996 dollars).

iii. Purchase Price (Cost of a Standard Rebuild)

According to Section 85.1403(b)(1)(iii)of the program regulation, the purchase price of equipment is defined as ''the price at which the equipment * * * is offered to the operator'', and ''excludes * * * costs * * * for a standard rebuild''. In Engelhard's original notification of intent to certify, Engelhard proposed a purchase price plus installation cost of $13,502, and a standard rebuild cost of $5,562. Thus, the net incremental life cycle cost proposed by Engelhard totaled $7,940 (in 1992 dollars). Engelhard's proposed standard rebuild cost of $5,562 was based on the maximum purchase price guaranteed by DDC in it's April 11, 1995 application for certification of the 6V92TA MUI upgrade kit.

DDC commented that Engelhard's proposed cost for a standard rebuild of $5,562 includes approximately $97 for the blower bypass valve, which is not always replaced during a standard rebuild. In addition, DDC noted some apparent inconsistencies with respect to current year dollars versus 1992 dollars. For example, Engelhard states in it's application that all costs are in 1992 dollars, while the $5,562 cost from DDC's April 11, 1995 application are in 1995 dollars.

JMI commented that basing the cost of a standard rebuild on the price DDC proposed for it's upgrade kit is not representative of the cost of a standard rebuild. JMI stated that numerous fleets receive a minimum 18 percent discount on DDC parts compared to the list price upon which Engelhard's standard rebuild cost was based. Applying an 18 percent discount to the $5,562 OE list price cost, JMI claims a standard rebuild cost of $4,561. In addition, JMI comments that fleets typically can rebuild using non-OE parts at a savings of 40 percent compared to OE list price. JMI states that this 40 percent discount results in a standard rebuild cost of $3,337. JMI did not indicate a cost associated with using a combination of non-OE parts and discounted OE parts, nor did they indicate which of these two proposed standard rebuild costs it considers more representative of the actual cost.

In response to DDC comments, EPA notes that the blower bypass valve is not included in the cost of a standard rebuild since it is not always replaced. Also, the cost analyses presented below are updated to reflect current dollars.

EPA announced the certification of the DDC MUI upgrade kit on the basis of meeting life cycle cost requirements in a Federal Register notice dated July 19, 1996 (61 FR 37734). In that July 19, 1996 notice, EPA responded to comments relating to the cost of a standard 6V92TA MUI rebuild, and determined that a ''weighted'' rebuild, which accounts for use of OE, non-OE, and rebuilt parts is likely more representative of typical fleet rebuilding practices than using only OE parts. That weighted rebuild analysis resulted in a cost of $3,747.66 (in 1995 dollars), and was based on the best information available at the time. Table E below provides a summary of that analysis, and is shown in December 1995 dollars.

TABLE E.—COST OF A WEIGHTED REBUILD SUMMARIZED FROM 61 FR 37734, JULY 19, 1996

[1995 Dollars]

Item in kit	OE list cost	Non-OE cost	OE list less 18%	Weighted rebuild [1]	DDC Kit
Cylinder Kit	$1,844.52	$1,139.94	$1,512.51	$1,391.05	....
Gasket Kit	220.16	132.10	180.53	164.74	....
Air Inlet Hose	14.95	8.97	12.26	11.19	....
Blower Bypass Valve	97.36	0.00	0.00	0.00	....
Fuel Injectors	444.96	266.98	364.87	332.96	....
LB Camshaft	581.84	349.10	477.11	435.38	....
RB Camshaft	581.84	349.10	477.11	435.38	....
Blower Assembly	442.80	199.26	0.00	199.26	....
Turbo Assembly	783.00	352.35	0.00	352.35	....
Heads Assembly	944.84	425.18	0.00	425.18	....
Totals	....	....	....	3,747.48	5,561.92

[1] The weighting factors used to arrive at each individual weighted component cost are described in detail in the **Federal Register** notice referenced above.

In letters dated October 8, 1996, and October 21, 1996, Engelhard provided additional information to EPA in response to JMI's cost comments on the ETX kit, and in response to the weighted rebuild cost shown in Table E. As a result of contacting various fleets and parts distributors, Engelhard states that several adjustments to EPA's weighted cost approach are warranted.

Engelhard states that the OE list prices for the various engine components have risen significantly since the DDC approval. Engelhard also states that JMI's assumption that fleets typically receive an 18 percent discount from OE list is incorrect. DDC provided current OE list costs and suggested fleet costs of individual engine components. Table F below represents an update of the weighted cost analysis presented in the July 19, 1996 Federal Register, updated to reflect current (October 1996) OE list and fleet prices reported by DDC.

TABLE F.—COST OF A WEIGHTED REBUILD [1]

[October 1996 Dollars]

Item in kit	OE list cost	Non-OE cost	OE list less 18%	Weighted rebuild [1]
Cylinder Kit	$1,967.34	$1,174.02	$1,691.40	$1,522.74
Gasket Kit	234.82	140.89	201.27	181.59
Air Inlet Hose	16.20	9.72	13.88	12.52
Blower Bypass Valve	103.85	0.00	0.00	0.00
Fuel Injectors	484.98	290.99	447.96	396.79
LB Camshaft	738.80	443.28	633.25	571.32
RB Camshaft	738.80	443.28	633.25	571.32
Blower Assembly	488.01	219.60	0.00	219.60
Turbo Assembly	801.00	360.45	0.00	360.45
Heads Assembly	1,083.56	487.60	0.00	487.60
Totals	....	....	....	4,323.93

[1] This table is intended to represent the weighted rebuild cost analysis from Table E above, update to reflect October 1996 dollars.

In addition to updating EPA's previous cost analysis to reflect current prices, Engelhard identified several cost areas of the previous weighted cost analysis it felt should be modified. First, Engelhard states that typical non-OE parts cost 25 percent less than the OE part, compared to the 40 percent assumed in the weighted rebuild analysis of the July 19, 1996 Federal Register. Engelhard also notes that some aftermarket parts actually cost more than the OE part. Engelhard contacted DDC, two parts distributors, and various transits to obtain this information. JMI, on the other hand, contacted only one parts distributor to form the basis of it's comments. EPA believes that Engelhard's estimation of non-OE part cost differential is more consistent with information in a study conducted for the California Air Resources Board on heavy-duty diesel rebuilding.[2] The authors of the study contacted four parts distributors and found that aftermarket parts are generally less expensive than

[2] ''Survey of Heavy-Duty Engine Rebuilding, Reconditioning, and Remanufacturing Practices'', August 1987, CARB Contract #A4–152–32, Prepared by Sierra Research, Inc.

OE parts. Comparing the cost differential of a limited number of parts, the aftermarket parts cost about 10 to 20 percent less than OE parts. Based on this information, and the sources contacted for that information, EPA believes that the 25 percent cost difference noted by Engelhard is likely more representative than the 40 percent difference claimed by JMI.

Second, Engelhard states that the weighted cost approach should be adjusted to reflect an additional cost to transit operators who rebuild in-house, because parts are occasionally unrebuildable due to catastrophic failure. Engelhard stated that 10 percent of turbochargers and blowers are not rebuildable, and that 50 percent of cylinder heads are not rebuildable. This information is consistent with EPA's current understanding based on discussions with DDC. When parts are unrebuildable, a transit operator would typically purchase a new component at fleet cost. The nominal cost of these components assumes the exchange of a rebuildable core. If the core is not rebuildable, then the operator pays a core charge plus the nominal cost of the component. The sum of the component fleet price plus the core charge represent additional costs to fleets that rebuild in-house, due to unrebuildable parts. When weighted based on the frequency at which the part is unrebuildable, it yields an additional cost on a per components basis. EPA's weighted rebuild from the July 19, 1996 Federal Register assumes in-house rebuild of three components: the turbocharger, the blower, and the heads. Therefore, Table G below summarizes estimates of the additional costs related to the in-house rebuild of these parts.

TABLE G.—IMPACT OF UNREBUILDABLE PARTS

[1996 Dollars]

Item	OE fleet price	In-house rebuild cost	Percent damaged	Core charge	Added Cost (OE fleet price + core) (damaged)	Actual in-house rebuild Cost
Blower	$450.73	$219.60	10	$466.00	$91.67	$311.28
Turbo	739.81	360.45	10	300.00	103.98	464.43
Heads	1,000.78	487.60	50	425.00	712.89	1,200.49

Finally, Engelhard states that OE parts carry a 100,000 mile warranty, while transit remanufactured parts and non-OE parts carry less, if any, warranty. Engelhard believes the cost implications of the warranty coverage should be included in the analysis with respect to use of non-OE and transit remanufactured parts, and provides discussion.

EPA does not dispute that some additional cost might be associated with different warranties provided by different part manufacturers. However, the cost impacts associated with warranties cannot be adequately quantified based on the available information. EPA believes that any additional cost would be related to repairs necessary for non-OE parts failing beyond the warranty for the non-OE part, but within the warranty period required for equipment certified under this program. No information has been provided on this subject, but the impact of this analysis on life cycles costs is expected to be minimal.

In summary, EPA is making the following three adjustments to its analysis of the cost of a weighted rebuild described in the July 19, 1996 Federal Register. First, all costs are updated to reflect October 1996 dollars (this singular revision is shown in Table F). Second, the weighted rebuild is modified to reflect non-OE parts cost of 25 percent less than OE cost, rather than 40 percent. Finally, the costs of unrebuildable parts cores are reflected in the costs of these three components, as discussed previously, for fleets rebuilding parts in-house. Table H shows the cost of a weighted rebuild including the three aforementioned adjustments.

TABLE H.—COST OF A WEIGHTED REBUILD (REFLECTING IMPACT OF UNREBUIDABLE PARTS AND 25 PERCENT NON-OE PARTS DISCOUNT)

[1996 Dollars]

Item in kit	OE list cost	Non-OE Cost	OE fleet price	Weighted rebuild
Cylinder Kit	$1,967.34	$1,174.02	$1,691.40	$1,522.74
Gasket Kit	234.82	176.12	201.27	193.07
Air Inlet Hose	16.20	12.15	13.88	13.32
Blower Bypass Valve	103.85	0.00	0.00	0.00
Fuel Injectors	484.98	363.74	447.96	420.50
LB Camshaft	738.80	554.10	633.25	607.45
RB Camshaft	738.80	554.10	633.25	607.45
Blower Assembly	488.01	311.28	0.00	311.28
Turbo Assembly	801.00	464.43	0.00	464.43
Heads Assembly	1,083.56	1,200.49	0.00	1,200.49
Totals	....	....	....	5,340.72

EPA believes that, for the purposes of determining purchase price for the Engelhard ETX kit, the cost of a standard rebuild for a DDC 6V92TA MUI engine is best approximated by the weighted rebuild costs shown in Table H. EPA uses the $5,340.72 cost (in 1996 dollars) as the cost of a standard rebuild to determine the life cycle cost of this equipment.

iv. Catalyst Installation

As defined in 40 CFR 85.1403 (b)(1)(ii)(B), the installation cost of certified equipment is ''the labor cost of installing the equipment on an urban bus engine, incremental to a standard rebuild, based on a labor rate of $35 per hour'' (in 1992 dollars). Engelhard states the CMX–5 catalyst unit requires a maximum time of six hours to install on an urban bus engine, or $210 (in 1992 dollars). The urban bus engines for which this equipment is intended were not originally equipped with catalytic convertors. Therefore, the muffler unit must be removed from the engine, and the CMX–5 unit installed in its place. As a result, the $210 is incremental to the cost of a standard rebuild.

v. Life Cycle Cost Calculation

In a December 16, 1996 letter to EPA, Engelhard revised the price it will charge transit operators for the ETX kit. The maximum purchase price for the ETX kit purchased wholly from Engelhard (the supply option upon which EPA is basing its determination of compliance with the life cycle cost requirements) is stated to be $13,425 (in October 1996 dollars). This cost includes all components of the ETX kit, including the coated cylinder heads and piston kits, the CMX–5 converter muffler, and the turbocharger, blower, blower drive gear, blower bypass valve, camshafts, fuel injectors, air inlet hose, and gasket kit.

Based on this maximum purchase price, EPA determines that the ETX kit complies with the $7940 (in 1992 dollars) life cycle cost requirement of section 85.1403(b) for equipment meeting the 0.10 g/bhp-hr PM standard. A summary of life cycle costs is shown in Table I below.

TABLE I.—LIFE CYCLE COST ANALYSIS

Cost item	Cost in 1996 dollars	Cost in 1992 dollars
Maximum ETX Kit Purchase Price	$13,425.00	$11,898.47
2% Fuel Economy Penalty	635.64	563.36
Catalyst Installation (6 hours)	236.94	210.00
Cost of Standard Rebuild	(5,340.72)	(4,733.44)
Total Life Cycle Cost	8,956.83	7,938.37

g. California Engines

DDC commented that Engelhard's request for certification of the ETX system on California engines is unsupported by any data. DDC notes that the NO_X standard for California engines for 1984 and later model years is more stringent than the corresponding federal NO_X standard. While Engelhard's test engine NO_X level of 10.5 g/bhp-hr (secondary ETX certification test) complies with the 1989 and earlier federal NO_X standard, it exceeds the California standards for these same model years. DDC comments that while the fuel injector part number listed in the NIC for the 277 HP and 253 HP California versions of the ETX kit have a slight internal timing retard which would tend to reduce NO_X, these same injectors would also tend to increase PM. DDC also comments that the NO_X reductions resulting from the slight internal timing retard would not be sufficient to ensure that California engines remained below applicable California NO_X standards. DDC believes the certification of the ETX kit for California engines must be predicated on evidence which shows such engines comply with the 0.10 g/bhp-hr PM standard and comply with applicable California NO_X standards.

EPA agrees with DDC and determines that insufficient data have been provided to justify certification of the ETX kit for use on engines originally certified as meeting California emissions standards. Section 85.1406(a)(1) of the program regulations state, in part, that the equipment certifier must demonstrate that the equipment ''will not cause the urban bus engine to fail to meet any applicable Federal emission requirements set for that engine''.

However, a unique situation exists with respect to engines originally certified as meeting California standards. The DDC 6V92TA MUI engines have, since the 1977 model year, been certified to a more stringent NO_X standard in California. EPA has granted California several waivers of federal preemption in order to allow these more stringent standards. Engelhard must provide emission data to demonstrate that California engines, when retrofit with the ETX kit, will not exceed applicable California standards. Engelhard has provided no such data. In fact, the data which were presented indicate that engines with the ETX kit installed will substantially exceed the California NO_X standard. EPA agrees with DDC that if modifications were made to the ETX kit or its components to reduce NO_X from the level demonstrated by Engelhard's test engine, to the levels required to comply with California standards, then, in the absence of additional PM data, it is unclear whether the equipment would comply with the 0.10 g/bhp-hr standard. This is because, generally speaking, engine design measures taken to reduce NO_X emissions would likely increase PM emissions. Therefore, EPA is not certifying this equipment for use in California at this time, and today's Federal Register notice does not trigger the 0.10 g/bhp-hr PM standard of the urban bus retrofit program for engines originally certified as meeting California emissions standards.

Engelhard may submit an additional notification of intent to certify the ETX kit for use on engines certified as meeting California emissions standards. EPA would make the notification available for a 45-day public review and comment period. After resolution of comments and concerns, EPA would render a certification decision. In addition, EPA understands the California Air Resources Board's (ARB's) view that equipment certified under the urban bus program, to be used in California, must be provided with an executive order exempting it from the anti-tampering prohibitions of that State.

h. Other Comments

In its November 22, 1996 letter, DDC stated its concern that the description of the ETX kit has changed substantially since the May 6, 1996 Federal Register notice seeking public comment. Specifically, DDC states that the removal of coated exhaust parts and the changing of fuel injector height and throttle delay settings should have prompted another opportunity for public comment.

EPA notes that only two substantive changes have been made to the ETX since the initial notification of intent to certify. Removal of coated exhaust parts by Engelhard was done in response to public comments, including DDC's. Concerns were expressed by both the public and EPA about the ability to control the coating process on such parts considering the part-to-part variability in surface area, shape, etc. Engelhard acknowledged that the coated exhaust parts were originally included in the ETX kit to provide an extra compliance margin relative to the 0.10 g/bhp-hr PM standard, but were not absolutely necessary to comply. Since these parts were not considered ''essential'' by Engelhard to comply with the standard, they were removed from the kit. Engelhard believes that the coating on the piston crowns and combustion chambers is necessary to provide an adequate compliance margin. Any additional public comment on this matter would be moot since the coated exhaust components are no longer present in the kit.

The second change to the ETX kit involved the fuel injector height and throttle delay settings. Engelhard originally proposed settings of 1.460 inches and 0.594 inches, respectively (the OEM settings for most engines covered by this application are 1.466 inches and 0.636 inches, respectively). The reason Engelhard modified the OEM settings in its original application was to ensure compliance with FTP cycle performance statistics, rather than for any specific engine or emissions related performance reasons. (In fact, the settings originally proposed by Engelhard would tend to have a negative impact on PM emissions.) When Engelhard conducted supplemental testing requested by EPA to address fuel economy and emissions issues, Engelhard was able to comply with FTP cycle statistics using the OEM settings of 0.636 inches and 1.466 inches. While returning these settings to the OEM specifications is a change, EPA believes it does not warrant reopening the comment period because the change is minor and directionally would tend to reduce PM emissions.

JMI and DART expressed concern about possible toxic emissions related to the ETX kit. DART questions whether, during assembly of the engine, coating material may become ''airborne'', resulting in a potential health concern. In addition, DART and JMI question whether the combustion process may result in undesirable products. JMI postulates that free heavy metals, such as cobalt, molybdenum, nickel, chromium, boron, silicon, and vanadium, may be released if the coating becomes cracked or spalled. Such free metals, JMI states, when exposed to sulfur from diesel fuel at high temperatures and pressures (2200 degrees Fahrenheit, and 5 to 8 atmospheres), could react to form ''a variety of toxic compounds''. In addition, JMI states this could result in deactivation of the catalyst unit located in the exhaust stream.

EPA does not believe the conditions upon which JMI's (and DART's) concern is based will be present in engines using the ETX kit. Primarily, JMI's concern is based on an assumption that the GPX–5m coating is not durable, and thus will spall and crack, allowing free metals to react with sulfur. As described elsewhere in today's notice, durability testing is not required under this program. However, as discussed above, the available data does not indicate that the GPX–5m coating is not durable. In addition, Engelhard contends that any metals used in the GPX–5m coating are applied to surfaces in such manner that machining is required for removal.

DDC comments that it should not be responsible for providing emission defect or performance warranties under the urban bus retrofit/rebuild program for equipment certified by Engelhard, even though DDC parts are required to be used.

Engelhard, as the equipment certifier, must provide all warranties required by the urban bus retrofit/rebuild regulation. Engelhard is aware of its responsibility to provide such warranties, including cases where transit operators obtain DDC parts from Engelhard or through their normal supply channels under the approved supply options.

III. Certification Approval

The Agency has reviewed this notification, along with comments received from interested parties, and finds the equipment described in this notification of intent to certify:

(1) Complies with a particulate matter emissions standard of 0.10 g/bhp-hr, without causing the applicable engine families to exceed other exhaust emission standards;

(2) Will not cause an unreasonable risk to the public health, welfare or safety;

(3) Will not result in any additional range of parameter adjustability; and

(4) Meets other requirements necessary for certification under the Retrofit/Rebuild Requirements for 1993 and Earlier Model Year Urban Buses (40 CFR Sections 85.1401 through 85.1415).

The Agency hereby certifies this equipment for use in the Urban Bus Retrofit/Rebuild Program as described below in Section IV.

IV. Transit Operator Responsibilities

Today's Federal Register notice announces certification of the above-described Engelhard equipment, when properly applied, as meeting the 0.10 g/bhp-hr particulate matter standard of the Urban Bus Retrofit/Rebuild Program for urban buses originally certified as meeting Federal emissions standards. Urban buses of the type described in Table C of today's notice, which were originally certified as meeting California emissions standards, are not covered the certification announced today. Affected urban bus operators who choose to comply with program 1 are required to use this, or other equipment that is certified as meeting the 0.10 g/bhp-hr particulate matter standard, for any engines listed in Table C which are rebuilt or replaced on or after September 15, 1997. The 0.10 g/bhp-hr PM standard is not triggered for urban buses originally certified as meeting California emission standards. Therefore, operators of such urban buses, who choose to comply with program 1, are not required to use such equipment until the 0.10 g/bhp-hr PM standard has been triggered for such engines.

Urban bus operators who choose to comply with program 2 may use the certified Engelhard equipment immediately, and those who use this equipment may claim the respective particulate matter certification level from Table C when calculating their Fleet Level Attained (FLA). Again, because this equipment is not certified as meeting the 0.10 g/bhp-hr PM standard for engines originally certified as meeting California emission standards, operators of such urban buses, who choose to comply with program 2, may not use this equipment to meet program requirements. In addition, such operators, when calculating their FLA, may not claim the PM levels shown in Table C because the program requires use of certified equipment.

As stated in the program regulations (40 CFR 85.1401 through 85.1415), operators should maintain records for each engine in their fleet to demonstrate that they are in compliance with the requirements of the Urban Bus Retrofit/Rebuild Program beginning on January 1, 1995. These records include purchase records, receipts, and part numbers for the parts and components used in the rebuilding of urban bus engines. Urban bus operators using supply options 2 and 3, as described previously in today's Federal Register notice, must be aware of their responsibility for maintenance of records pursuant to 40 CFR 85.1403 through 85.1404, because they do not purchase the complete ETX kit from Engelhard. Urban bus operators using supply option 2 or 3 must be able demonstrate that all parts used in the rebuilding of engines are in compliance with program requirements. In other words, such urban bus operators must be able demonstrate that all components of the kit certified in today's Federal Register notice are installed on applicable engines.

Dated: March 7, 1997.

Mary D. Nichols,

Assistant Administrator for Air and Radiation.

[FR Doc. 97–6505 Filed 3–13–97; 8:45 am]

BILLING CODE 6560–50–P

[OPPTS–140254; FRL–5593–3]

Access to Confidential Business Information by Science Applications International Corporation

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: EPA has authorized its contractor, Science Applications International Corporation (SAIC), of Reston, Virginia, access to information which has been submitted to EPA under all sections of the Toxic Substances Control Act (TSCA). Some of the information may be claimed or determined to be confidential business information (CBI).

DATES: Access to the confidential data submitted to EPA will occur no sooner than March 28, 1997.

FOR FURTHER INFORMATION CONTACT: Susan Hazen, Director, Environmental Assistance Division (7408), Office of Pollution Prevention and Toxics, Environmental Protection Agency, Rm. E–545, 401 M St., SW., Washington, DC 20460, (202) 554–1404, TDD: (202) 554–0551; e-mail: TSCA-Hotline@epamail.epa.gov.

SUPPLEMENTARY INFORMATION: Under contract number 68–W4–0005, contractor SAIC, of 11251 Roger Bacon Drive, Reston, VA, will assist the Office of Waste and Chemicals Management and Regional Offices RCRA Enforcement, Permitting and Assistance Program in the implementation of RCRA/TSCA related initiatives. Major areas of support include permitting activities, Subtitle D solid waste, corrective actions and RCRA program planning.

In accordance with 40 CFR 2.306(j), EPA has determined that under EPA contract number 68–W4–0005, SAIC will require access to CBI submitted to EPA under all sections of TSCA to perform successfully the duties specified under the contract. SAIC personnel will be given access to information submitted to EPA under all sections of TSCA. Some of the information may be claimed or determined CBI.

EPA is issuing this notice to inform all submitters of information under all sections of TSCA that EPA may provide SAIC access to these CBI materials on a need-to-know basis only. All access to TSCA CBI under this contract will take place at SAIC's site located at 18702 N. Creek Parkway, Bothell, WA.

SAIC will be authorized access to TSCA CBI at its facility under the EPA *TSCA Confidential Business Information Security Manual*. Before access to TSCA CBI is authorized at SAIC's site, EPA will approve SAIC's security certification statement, perform the required inspection of its facility, and ensure that the facility is in compliance with the manual. Upon completing review of the CBI materials, SAIC will return all transferred materials to EPA.

Clearance for access to TSCA CBI under this contract may continue until January 5, 1999.

SAIC personnel will be required to sign nondisclosure agreements and will be briefed on appropriate security procedures before they are permitted access to TSCA CBI.

List of Subjects

Environmental protection, Access to confidential business information.

Dated: March 7, 1997.

Oscar Morales,

Acting Director, Information Management Division, Office of Pollution Prevention and Toxics.

[FR Doc. 97–6517 Filed 3–13–97; 8:45 am]

BILLING CODE 6560–50–F

[ER–FRL–5478–4]

Environmental Impact Statements and Regulations; Availability of EPA Comments

Availability of EPA comments prepared February 24, 1997 Through February 28, 1997 pursuant to the Environmental Review Process (ERP), under Section 309 of the Clean Air Act and Section 102(2)(c) of the National Environmental Policy Act as amended. Requests for copies of EPA comments can be directed to the Office of Federal Activities at (202) 564–7167.

An explanation of the ratings assigned to draft environmental impact statements (EISs) was published in FR dated April 5, 1996 (61 FR 15251).

Draft EISs

ERP No. D–AFS–K65193–NV Rating EO2, Griffon Mining Project, Implementation, Issuance Plan of Operations Approval, Humboldt-Toiyabe National Forests, Ely Ranger District, White Pine County, NV.

Summary: EPA had environmental objections to the proposed project based on its potential impacts to a wet meadow and disturbance of more land for waste rock dumps, impacts to water quality and habitat in Ellison Creek, facilities design, and air quality. EPA requested additional information regarding water quality impacts and objectives, facilities design, mitigation measures, the waste rock characterization and handling plan, and access roads. EPA recommended that the Forest Service select as its preferred alternative Alternative C with backfilling of the Hammer Ridge pit.

ERP No. DC–NPS–K61029–CA Rating EC2, Yosemite National Park General Management Plan, Yosemite Housing Project, Updated Information on Yosemite Valley Housing Plan, New and Replacement Housing, Mariposa, Modera and Tuolumne Counties, CA.

Summary: EPA expressed environmental concerns that the new preferred alternative would move fewer park employees out of Yosemite Valley than previously identified alternatives, and an employee transportation system would not be developed. EPA recommended the analysis of an additional alternative which combines a more aggressive development of EL Portal housing with an alternative fuels employee transportation system.

ERP No. DS–NOA–E86002–00 Rating LO, Sapper Grouper Fishery, Amendment 8 to the Fishery Management Plan, Regulatory Impact Review, South Atlantic Region.

Summary: EPA lacked objections to the proposed 17 regulatory actions to improve fisheries in US EEZ and recommended more emphasis on nonpoint pollutions, as a factor exacerbated declines in fishery stock.

Final EISs

ERP No. F–BLM–K65188–CA Eagle Mountain Landfill and Recycling Center Project, Land Exchange, Right-of-Way Grants and COE Section 404 Permit Issuance, Riverside County, CA.

Summary: Review of the final EIS was not deemed necessary. No formal comment letter was sent to the preparing agency.

ERP No. F–FHW–E40738–NC US–220 Connecting the Star/Biscoe/Candor Bypass, Improvement, Funding, Right-of-Way, Possible COE Permit, Montgomery and Richmond County, NC.

Summary: Most of EPA's draft EIS comments were addressed adequately. EPA continued to have concerns about clearing of forested areas and noise impacts.

ERP No. F–TVA–E07013–TN Kingston Fossil Plant Alternative Coal Receiving Systems, New Rail Spur Construction near the Cities of Kingston and Harriman, Roane County, TN.

Summary: EPA expressed environmental concerns which include earthen causeway fill and impacts on low-income populations.

ERP No. F–USA–K11072–CA Camp Roberts Army National Guard Training Site, Implementation, Combined-Forces Training Activities, New Equipment Utilization and Range Modernization Program, Monterey and San Luis Obispo Counties, CA.

Summary: EPA had no objection to the proposed action. The Final EIS responds to our concerns, which involved air quality and NEPA issues.

Dated: March 11, 1997.

William D. Dickerson,

Director, NEPA Compliance Division, Office of Federal Activities.

[FR Doc. 97–6503 Filed 3–13–97; 8:45 am]

BILLING CODE 6560–50–M

[ER–FRL–5478–3]

Environmental Impact Statements; Notice of Availability

Responsible Agency: Office of Federal Activities, General Information (202) 564–7167 OR (202) 564–7153.

Weekly receipt of Environmental Impact Statements Filed March 03, 1997 Through March 07, 1997 Pursuant to 40 CFR 1506.9.

EIS No. 970075, Final EIS, AFS, OR, Stewart Mining Operation, Plan of Operation Approval, Implementation, City Creek, North Umpqua Ranger District, Umpqua National Forest, Forest, Douglas and Lane Counties, OR, *Due:* April 14, 1997, *Contact:* Debbie Anderson (541) 406–3532.

EIS No. 970076, Final EIS, FHW, UT, Norman H. Bangerter Highway (Previously Known as the West Valley Highway) 12600 South Street to I–15, Funding and COE Section 404 Permit, in the Cities of Bluffdale, Riverton and Draper, Salt Lake County, UT, *Due:* April 14, 1997, *Contact:* Tom Allen (801) 963–0181.

EIS No. 970077, Draft EIS, BLM, MT, Cooke City Area Mineral Withdrawal, Implementation, Gallatin and Custer National Forests, Cooke City, Park County, MT, *Due:* April 28, 1997, *Contact:* Larry Timchak (406) 255–0322.

EIS No. 970078, Draft EIS, NOA, Monfish Fishery Regulations, Northeast Multispecies Fishery (FMP), Fishery Management Plan, Amendment 9, Implementation, Exclusive Economic Zone, off the New England and Mid-Atlantic Coast, *Due:* April 28, 1997, *Contact:* E. Martin Jaffe (508) 281–9272.

EIS No. 970079, Final EIS, USN, FL, Programmatic EIS—Mayport Naval Station, Evaluation of Facilities Development Necessary to Support Potential Aircraft Carrier Homeporting, Duval County, FL, *Due:* April 14, 1997, *Contact:* Ronnie Lattimore (803) 820–5888.

EIS No. 970080, Draft EIS, FRC, AL, North Alabama Natural Gas Pipeline Facilities, Construction and Operation, COE Section 10 and 404 Permits, Right-of-Way and NPDES Permits, AL, *Due:* April 28, 1997, *Contact:* Paul McKee (202) 208–1611.

EIS No. 970081, Final EIS, AFS, MT, Castle Mountains Allotment Management Plan, Implementation, Lewis and Clark National Forest, Musselshell and King Hill Ranger Districts, White Sulphur Springs, Meagher County, MT, *Due:* April 14, 1997, *Contact:* Dave Wanderass (406) 632–4391.

EIS No. 970082, Draft EIS, TVA, AL, Bellefonte Nuclear Plant Conversion Project, Construction and Operation, NPDES Permit and COE Section 404 Permit, Tennessee River near Hollywood, AL, *Due:* May 05, 1997, *Contact:* Greg Askew (423) 632–6418.

Amended Notices

EIS No. 960470, Draft EIS, COE, IL, Chicagoland Underflow Plan, McCook Reservoir Construction and Operation for Temporary Retention of Floodwaters in Metropolitan Chicago, Implementation, Cook County, IL, *Due:* April 24, 1997, *Contact:* Keith Ryder (312) 353–6400. Published FR—10–11–96—Review Period Reopened.

EIS No. 970015, Final EIS, COE, VA, Lower Virginia Peninsula Regional Raw Water Supply Plan, Permit Approval, Cohoke Mill Creek, King William County, VA, *Due:* May 27, 1997, *Contact:* Pamela K. Painter (757) 441–7654. Published FR 01–24–97—Review Period Extended.

Dated: March 11, 1997.

William D. Dickerson,

Director, NEPA Compliance Division, Office of Federal Activities.

[FR Doc. 97–6504 Filed 3–13–97; 8:45 am]

BILLING CODE 6560–50–M

[FRL–5709–5]

Ozone, Particulate Matter and Regional Haze Implementation Programs Subcommittee Meeting

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of meeting.

SUMMARY: On September 11, 1995 (60 FR 47172), the EPA announced the establishment of the Ozone, Particulate Matter and Regional Haze Implementation Programs Subcommittee under the Clean Air Act Advisory Committee (CAAAC). The CAAAC was established on November 8, 1990 (55 FR 46993) pursuant to the Federal Advisory Committee Act (FACA) (5 U.S.C. app I). The purpose of the Subcommittee is to provide advice and recommendations on integrated approaches for implementing potentially new national ambient air quality standards (NAAQS) for ozone and particulate matter, as well as a regional haze program.

DATES: Notice is hereby given that the Subcommittee for Development of Ozone, Particulate Matter and Regional Haze Implementation Programs will hold its next public meeting on Tuesday, April 8, 1997 (from 8:30 a.m. to 4:30 p.m.) and Wednesday, April 9, 1997 (from 8:00 a.m. to 5:00 p.m.).

ADDRESSES: The public meeting will be held at the Fairview Park Marriott, 3111 Fairview Park Drive, Falls Church, Virginia 22042.

FOR FURTHER INFORMATION CONTACT: For further information on the Subcommittee for Development of Ozone, Particulate Matter and Regional Haze Implementation Programs, please contact Mr. William F. Hamilton, Designated Federal Officer, at 919–541–5498, or by mail at U.S. EPA, Office of Air Quality Planning and Standards, MD–12, Research Triangle Park, NC 27711. When a draft agenda is developed, a copy can be downloaded from the: (1) Ozone/Particulate Matter/Regional Haze FACA Bulletin Board, which is located on the Office of Air Quality Planning and Standards Technology Transfer Network (OAQPS TTN); (2) the OAQPS TTN Web Site (http://ttnwww.rtpnc.epa.gov); or (3) by contacting Ms. Denise M. Gerth at 919–541–5550.

Dated: March 6, 1997.

Henry C. Thomas,

Acting Director, Office of Air Quality Planning and Standards.

[FR Doc. 97–6508 Filed 3–13–97; 8:45 am]

BILLING CODE 6560–50–P

[PF–717; FRL–5590–2]

Bayer Corporation; Pesticide Tolerance Petition Filing

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of filing.

SUMMARY: This notice announces the filing of a pesticide petition proposing regulations establishing tolerances for residues of the pyrethroid cyfluthrin in or on the raw agricultural commodities (RACs) group citrus, fruits and to establish a maximum residue limit for cyfluthrin on citrus oil and dried pulp. This notice includes a summary of the petition that was prepared by Bayer Corporation.

DATES: Comments, identified by the docket control number [PF–717], must be received on or before April 14, 1997.

ADDRESSES: By mail, submit written comments to Public Response and Program Resources Branch, Field Operations Division (7506C), Office of Pesticide Programs, Environmental Protection Agency, 401 M St. SW., Washington, DC 20460. In person, bring comments to Rm. 1132, CM #2. 1921 Jefferson Davis Highway, Arlington, VA 22202.

Comments and data may also be submitted electronically be sending electronic mail (e-mail) to: opp-docket@epamail.epa.gov. Electronic comments must be submitted as an ASCII file avoiding the use of special characters and any form of encryption. Comments and data will also be accepted on disks in WordPerfect 5.1 file format or in ASCII file format. All comments and data in electronic form must be identified by docket control number [PF–717]. Electronic comments on this notice may be filed online at many Federal Depository Libraries. Additional information on electronic submissions can be found below this document.

Information submitted as a comments concerning this document may be claimed confidential by marking any part or all of that information as ‘‘Confidential Business Information’’ (CBI). CBI should not be submitted through e-mail. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. A copy of the comment that does not contain CBI must be submitted for inclusion in the public record. Information not marked confidential may be disclosed publicly by EPA without prior notice. All written comments will be available for public inspection in Rm. 1132 at the address given above, from 8:30 a.m. to 4 p.m., Monday through Friday, excluding legal holidays.

FOR FURTHER INFORMATION CONTACT: By mail: George T. LaRocca, Product Manager (PM) 13, Registration Division (7505C), Office of Pesticide Programs, Environmental Protection Agency, 401 M St., SW., Washington, DC 20460. Office location, telephone number, and e-mail address: Rm. 200, CM #2, 1921 Jefferson Davis Highway, Arlington, VA 22202. (703) 305–6100; larocca.george@epamail.epa.gov.

SUPPLEMENTARY INFORMATION: EPA has received pesticide petitions (PP) 4F4313 and 4H5687 from Bayer Corporation, 8400 Hawthorn Road, Kansas City, MO 64120. The petition proposes, pursuant to section 408(d) of the Federal Food Drug and Cosmetic Act, 21 U.S.C. section 346a, to amend 40 CFR 180.436 to establish tolerances for residues of the insecticide cyfluthrin, [cyano[4-fluoro-3-phenoxyphenyl]-methyl-3-[2,2-dicloroethenyl]-2,2-dimethylcyclopropanecarboxylate] in or on the raw agricultural commodities group citrus, fruits at 0.2 part per million (ppm) and the processed commodities citrus, oil and citrus, dried pulp at 0.3 part per million (ppm). The proposed analytical method is gas chromatography equipped with electron capture detector.

As required by section 408(d) of the FFDCA, as recently amended by the Food Quality Protection Act, Bayer Corporation included in the petition a summary of the petition and authorization for the summary to be published in the Federal Register in a notice of receipt of the petition. The summary represents the views of Bayer Corporation; EPA is in the process of evaluating the petition. As required by section 408(d)(3) EPA is including the summary as a part of this notice of filing. EPA may have made minor edits to the summary for the purpose of clarity.

I. Petition Summary

A. Residue Chemistry

1. *Use pattern*. Baythroid 2 will be used on citrus only in California and Arizona, to control citrus thrips. A dosage of 6.4 fluid ounces of Baythroid 2 (0.1 lb active ingredient per acre) will be applied by ground equipment only, in sufficient water for complete coverage of foliage in dilute or concentrate sprays, but not less than 25 gallons per acre. A single application may be made per season.

2. *Plant metabolism*. The metabolism of cyfluthrin in plants is adequately understood. Studies have been conducted to delineate the metabolism of radiolabeled cyfluthrin in various crops all showing similar results. The residue of concern is cyfluthrin.

3. *Analytical methodology*. Adequate analytical methodology (Gas liquid chromatography with an electron capture detector) is available for enforcement purposes.

The established tolerances for residues of cyfluthrin in/on eggs, milks, fat, meat and meat by-products of cattle, goats, hogs, horses, sheep and poultry are adequate to cover secondary residues resulting from the proposed use as delineated in 40 CFR 180.6(a)(2).

4. *Magnitude of the residue*. On December 20, 1993, Bayer Corp. filed a petition (PP 4F4313) for a tolerance for residues of cyfluthrin on the raw agricultural commodity, citrus and proposed food/feed additive regulation (4H5687) for citrus oil, citrus dried pulp, and citrus molasses under section 409 of FFDCA. A request was filed May 2, 1996, to withdraw the feed additive petition for citrus molasses, submitted in response to EPA’s determination that citrus molasses is no longer considered a significant feed item. See EPA’s final 860 Series Residue Chemistry Guidelines (860.1000) published as public drafts on August 25, 1995 (60 FR 44343) (formerly Table II of Subdivision O, Residue Chemistry, of the Pesticide Assessment Guidelines).

The food/feed additive petition for citrus oil and citrus dried pulp has been revised to propose these tolerances at 0.3 ppm under section 408 instead section 409 in accordance the Food Quality Protection Act.

The proposed section 408 tolerance for cyfluthrin on citrus is 0.2 ppm. The highest average residue found in crop field trials for cyfluthrin on citrus fruits was 0.06 ppm. A processing study showed that in producing citrus oil and dried pulp residues concentrated 530 (a concentration factor of 5.3×). Thus with this information it is likely that cyfluthrin residues of 0.32 ppm (0.06 × 5.3) could occur in citrus oil and dried pulp.

B. Toxicological Profile

The data base for cyfluthrin is essentially complete. Data lacking but desirable are an acute neurotoxicity study in rats and a 90-day neurotoxicity study in rats. Although these data are lacking, Bayer Corp. believes there is sufficient toxicity data to support the proposed tolerance and these missing data will not significantly change the risk assessment. In a letter dated November 2, 1995, Bayer Corp. has committed to submit the acute neurotoxicity study by December 1996 and the 90-day neurotoxicity study by May 1997.

The toxicology data cited in support of the tolerance include:

1. *Chronic effects*. A 12-month chronic feeding study in dogs with a no-observed effect level (NOEL) of 4 mg/kg/day. The lowest effect level (LEL) for this study is established at 16 mg/kg/day, based on slight ataxia, increased vomiting, diarrhea and decreased body weight.

A 24-month chronic feeding/carcinogenicity study in rats with a NOEL of 2.5 mg/kg/day and LEL of 6.2 mg/kg/day, based on decreased body weights in males, decreased food consumption in males, and inflammatory foci in the kidneys in females.

2. *Acute toxicity*. For the purposes of assessing acute dietary risk, the Agency has used an oral developmental toxicity study in rabbits with a maternal NOEL of 20 mg/kg/day and a maternal LEL of 60 mg/kg/day, based on decreased body weight gain and decreased food consumption during the dosing period. A fetal NOEL of 20 mg/kg/day and a fetal LEL of 60 mg/kg/day were also observed in this study. The LEL was based on increased resorptions and increased postimplantation loss.

3. *Carcinogenicity*. A 24-month carcinogenicity study in mice was conducted. There were no carcinogenic effects observed under the conditions of the study.

A 24-month chronic feeding/carcinogenicity study in rats was conducted. There were no carcinogenic effects observed under the conditions of the study.

Mutagenicity tests were conducted, including several gene mutation assays (reverse mutation and recombination assays in bacteria and a Chinese hamster ovary(CHO)/HGPRT assay); a structural chromosome aberration assay (CHO/sister chromatid exchange assay); and an unscheduled DNA synthesis assay in rat hepatocytes. All tests were negative for genotoxicity.

4. *Other*. A metabolism study in rats showed that cyfluthrin is rapidly absorbed and excreted, mostly as conjugated metabolites in the urine, within 48 hours. An enterohepatic circulation was observed.

C. Aggregate Exposure

A chronic dietary exposure/risk assessment was performed for cyfluthrin using a Reference Dose (RfD) of 0.025 mg/kg bwt/day, based on a NOEL of 50 ppm (2.5 mg/kg bwt/day) and an uncertainty factor of 100. The NOEL was determined in a 2-year rat feeding study. The endpoint effects of concern were decreased body weights in males and inflammation of the kidneys in females at the LEL of 6.2 mg/kg/day. For purposes of this dietary exposure/risk assessment tolerance level residues were used and percent crop treated assumption made for some of the commodities. The current estimated dietary exposure for the overall U.S. population resulting from established tolerances 0.009420 mg/kg/bwt/day or 37.6 percent of the RfD. The current estimated dietary exposure for the subgroup population exposed to the highest risk, non-nursing infants less than 1 year old, 0.025266 mg/kg bwt/day or 101 percent of the RfD. Although the estimate of dietary exposure for the subgroup, non-nursing infants less than 1 year old, is slightly higher than the Agency's level of concern, i.e., greater than 100 percent of the RfD, Bayer Corp. believes that actual exposure and risk would be lower. The basis for this is that the risk reflects a higher than actual dietary exposure because it assumes that 100 percent of most commodities for which cyfluthrin tolerances exist have cyfluthrin residues and that all will bear residue levels as high as the tolerances. In reality, all these commodities will not have residues of this pesticide and actual levels will be lower than tolerance levels. To assess the dietary exposure from the establishment of the proposed citrus tolerances, the incremental increase in dietary exposure was taken from the dietary exposure analysis conducted by the Agency. These estimates are based on the assumption that 100 percent of the citrus crop in the U.S. would be treated with cyfluthrin. In reality, this use of cyfluthrin will be limited to California and Arizona only for the control of citrus thrips. For the prior six years, cyfluthrin has been utilized in the California's Central Valley under the provisions of a FIFRA section 18 Emergency Exemption. In 1995, approximately 77,000 out of 170,000 acres (46 percent) of the citrus grown in Central Valley was treated with cyfluthrin. Assuming that a similar proportion of acreage, that is 46 percent, would be treated throughout California and Arizona, the total estimated acreage treated with cyfluthrin would be 94,000 acres. This represents only 9.4 percent of the 1,026,000 fruit bearing acres of citrus grown in the U.S. Therefore, a 10 percent treated crop adjustment to the dietary exposure can be considered appropriate.

Adding this incremental exposure to the current estimated dietary exposure results in a total dietary exposure for the U.S. population of 0.0094934 mg/kg bwt/day representing 38 percent of RfD. The highest exposure group, non-nursing infants will increase only very slightly, to 0.253653 mg/kg bwt/day representing 101.4 percent of the RfD. As described above, although this still slightly exceeds the RfD, actual exposure is expected to be much less.

Generally speaking, EPA has no cause for concern if the total dietary exposure from residues for uses for which there are published and proposed tolerances is less than the RfD. Therefore Bayer concludes that the chronic dietary risk of cyfluthrin, as estimated by the dietary risk assessment, does not appear to be of concern.

Other potential sources of exposure to residues of pesticides are residues in drinking water and exposure from non-occupational sources. Based on available studies used in previous EPA assessments, Bayer Corp. does not anticipate exposures to cyfluthrin in drinking water. Non-occupational exposure to cyfluthrin may occur as a result of inhalation or contact from indoor residential, indoor commercial, and outdoor residential uses. The Agency does not currently have reliable data to determine aggregate exposures from these sources. However, determinations of worst case exposure from inhalation in indoor settings (continuous exposure at saturation vapor concentration) should indicate that adequate margins of safety exist even under these conditions. Since this evaluation greatly overestimates exposure, the contribution to aggregate exposure from inhalation in normal uses would be expected to be negligible. Estimations of outdoor residential exposure have been required for cyfluthrin in a data call-in issued in 1995. These data are being generated by the Outdoor Residential Exposure Task Force (ORETF). However, available data show that the acute dermal toxicity of cyfluthrin is very low, with the LD_{50} being greater than 5,000 mg/kg, the highest dose tested. Sub-acute (21–day) dermal toxicity data showed only localized (skin) effects at higher level exposures (1,000 mg/kg/day and 340 mg/kg/day). Other than skin effects at these high exposure levels, no effects were observed at any exposure levels, the highest level tested being 1,000 mg/kg/day. The use rate for cyfluthrin on residential turf is 1 g (1,000 mg) active ingredient per 1000 square feet which would indicate that potential exposures would be well below levels tested. In addition, the localized skin effects seen at the prolonged higher exposures in animal tests have not been reported for non-occupational exposures to cyfluthrin in currently accepted uses, indicating that exposures are below the threshold of any observable effects. Indoor uses are limited to areas with little or no contact, so exposures would be expected to be even less. Thus, the dermal route of exposure does not appear to be significant and the contribution to aggregate exposure from dermal contact would be expected to be negligible.

In consideration of potential cumulative effects of cyfluthrin and other substances that have a common mechanism of toxicity, there are currently no available data or other reliable information indicating that any toxic effects produced by cyfluthrin would be cumulative with those of other chemical compounds; thus only the potential risks of cyfluthrin have been considered in this assessment of its aggregate exposure.

D. Safety Determinations

1. *U.S. population in general.* Using the conservative exposure assumptions described above and based on the completeness and reliability of the toxicity data it can be concluded that total aggregate exposure to cyfluthrin from all current uses as well as the proposed tolerance and maximum residue levels for the use of cyfluthrin on citrus will utilize little more than 38 percent of the RfD for the U.S. population. EPA generally has no concerns for exposures below 100 percent of the RfD, because the RfD represents the level at or below which daily aggregate exposure over a lifetime will not pose appreciable risks to human health. Thus, it can be concluded that there is a reasonable certainty that no harm will result from aggregate exposure to cyfluthrin residues.

2. *Infants and children.* In assessing the potential for additional sensitivity of infants and children to residues of cyfluthrin, the data from developmental studies in both rat and rabbit and a 2-generation reproduction study in the rat can be considered. The developmental toxicity studies evaluate any potential adverse effects on the developing animal resulting from pesticide exposure of the mother during prenatal development . The reproduction study evaluates any effects from exposure to the pesticide on the reproductive capability of mating animals through two generations, as well as any observed systemic toxicity.

The toxicology data cited in support of the tolerance include: An oral developmental toxicity study in rats with a maternal and fetal NOEL of 10 mg/kg/day (highest dose tested). An oral developmental toxicity study in rabbits with a maternal NOEL of 20 mg/kg/day and a maternal LEL of 60 mg/kg/day, based on decreased body weight gain and decreased food consumption during the dosing period. A fetal NOEL of 20 mg/kg/day and a fetal LEL of 60 mg/kg/day were also observed in this study. The LEL was based on increased resorptions and increased postimplantation loss.

A developmental toxicity study in rats by the inhalation route of administration with a maternal NOEL of 0.0011 mg/l and a LEL of 0.0047 mg/l, based on reduced mobility, dyspnea, piloerection, ungroomed coats and eye irritation. The fetal NOEL is 0.00059 mg/l and the fetal LEL is 0.0011 mg/l, based on sternal anomalies and increased incidence of runts. A second developmental toxicity study in rats by the inhalation route of administration has been submitted to the Agency and is currently under review.

A three-generation reproduction study in rats with a systemic NOEL of 2.5 mg/kg/day and a systemic LEL of 7.5 mg/kg/day due to decreased parent and pup body weights. The reproductive NOEL and LEL are 7.5 mg/kg/day and 22.5 mg/kg/day respectively.

The Agency used the rabbit developmental toxicity study with a maternal NOEL of 20 mg/kg/day to assess acute dietary exposure and determine a margin of exposure (MOE) for the overall U.S. population and certain subgroups. Since this toxicological endpoint pertains to developmental toxicity the population group of concern for this analysis was women aged 13 and above, the subgroup which most closely approximates women of child-bearing age. The MOE is calculated as the ration of the NOEL to the exposure. For this analysis the Agency calculated the MOE to be over 600. Generally, MOE's greater than 100 for data derived from animal studies are regarded as showing no appreciable risk.

FFDCA Section 408 provides that EPA may apply an additional safety factor for infants and children in the case of threshold effects to account for pre- and post-natal effects and the completeness of the toxicity database. Based on current toxicological data requirements, the toxicology database for cyfluthrin relative to pre- and post-natal effects is complete. The no-effect-levels observed in the developmental and reproduction study are equivalent or higher than the NOEL from the 2-year rat feeding study, used with a 100 fold uncertainty factor to establish the reference dose.

Therefore, an additional uncertainty factor is not warranted and that the RfD at 0.025 mg/kg/day is appropriate for assessing aggregate risk to infants and children.

Using the conservative exposure assumptions described above, EPA has previously concluded that the residues from use of cyfluthrin on citrus will contribute the highest incremental increase to the aggregate exposure to the population subgroup children 1 to 6 years old, accounting for 3.9 percent of the RfD and giving a total dietary exposure from all uses of 95.9 percent of the RfD for this subgroup. However, this assessment was based on an assumption of 100 percent crop treated. When adjusted for a 10 percent crop treatment (as described in section B. above) the incremental exposure is negligible, increasing form the current 0.022985 mg/kg bwt /day (91.9 percent of the RfD) to 0.231522 mg /kg bwt/day or 92.6 percent of the RfD. For nursing infants current exposure is 0.005692 mg/kg bwt/day or 22.8 percent of the RfD. The use on citrus would increase exposure to 0.0057377 mg/kg bwt/day representing 22.9 percent of the RfD. For children 7 to 12, current exposure is 0.015237 mg/kg bwt/ day, 60.9 percent of the RfD. The use on citrus would increase this to 0.153416 mg/kg bwt /day, or 61.4 percent of the RfD. For non-nursing infants, the current is exposure is calculated to be 0.025267 mg/kg bwt /day, 101 percent of the RfD. The use on citrus would increase this slightly to 0.0253653 or 101.4 percent. Both the current and the resulting calculated exposure from adding the estimated exposure from citrus exposure are slightly higher than the Agency's level of concern. However, the Agency has previously assessed this risk in the evaluation of PP 2F4137 and believed the actual exposure and risk would be much lower. The basis for this was the fact that this calculated exposure assumes, with the exception of citrus, that 100 percent of the commodities for which cyfluthrin tolerance exists have residues and that the residues all bear residues as high as the tolerance levels. In reality, it is known that not all commodities will have cyfluthrin residues and actual levels will be lower than the tolerance values. In addition, the food commodity that contributes most to this slight exceedence is milk, at 88.2 percent of the RfD; 71.2 percent from milk fat and 17 percent from whole milk and milk sugars. However, metabolism data indicate that essentially all of the cyfluthrin will concentrate in milk fat and there would be negligible amounts in other components. Thus the 17 percent contribution from non-milk fat portions of milk is an overestimation of actual exposure, which would be below the RfD.

Generally, EPA has no cause for concern if the total aggregate exposure is less than the RfD, therefore it may be concluded that there is a reasonable certainty of no harm will result to infants and children.

E. Conclusions

The available data indicate that there is reasonable certainty of no harm from the incremental exposure resulting from the potential residues of cyfluthrin from the use of Baythroid 2, EPA Reg. No. 3125–351, on citrus. Thus in accordance with the provisions of the FFDCA as amended August 3, 1996, regulations to establish the tolerance and maximum residue levels to support this use can be effected.

F. International Tolerances

There are no Codex maximum residue levels (MRLs) established for residues ofcyfluthrin on citrus fruits or any resulting processed products.

II. Public Record

Interested persons are invited to submit comments on this notice of filing. Comments must bear a notation indicating the docket control number, [PF–717]. All written comments filed in response to this petition will be available in the Public Response and Program Resources Branch, at the address given above from 8:30 a.m. to 4 p.m., Monday through Friday, except legal holidays.

A record has been established for this notice under docket control number [PF–717] including comments and data submitted electronically as described below). A public version of this record, including printed, paper versions of electronic comments, which does not include any information claimed as CBI, is available for inspection from 8:30 a.m. to 4 p.m., Monday through Friday, excluding legal holidays. The public record is located in Rm. 1132 of the Public Response and Program Resources Branch, Field Operations Division (7506C), Office of Pesticide Programs, Environmental Protection Agency, Crystal Mall #2, 1921 Jefferson Davis Highway, Arlington, VA.

Electronic comments can be sent directly to EPA at:

opp-docket@epamail.epa.gov

Electronic comments must be submitted as ASCII file avoiding the use of special characters and any form of encryption.

The official record for this notice, as well as the public version, as described above will be kept in paper form. Accordingly, EPA will transfer all comments received electronically into printed, paper form as they are received and will place the paper copies in the official record which will also include all comments submitted directly in writing. The official record is the paper record maintained at the address in ''ADDRESSES'' at the beginning of this document.

Authority: 21 U.S.C. 346a.

List of Subjects

Environmental Protection, Administrative practice and procedure, Agricultural commodities, Pesticides and pests, Reporting and recordkeeping requirements.

Dated: March 7, 1997.

Stephen L. Johnson,

Director, Registration Division, Office of Pesticide Programs.

[FR Doc. 97–6516 Filed 3–13–97; 8:45 am]

BILLING CODE 6560–50–F

[OPP–50826; FRL–5592–3]

Issuance of an Experimental Use Permit

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: EPA has granted an experimental use permit to the following applicant. The permit is in accordance with, and subject to, the provisions of 40 CFR part l72, which defines EPA procedures with respect to the use of pesticides for experimental use purposes.

FOR FURTHER INFORMATION CONTACT: By mail: Mike Mendelsohn, Office of Pesticide Programs, Biopesticides and Pollution Prevention Division (7501W), Environmental Protection Agency, 401 M St., SW., Washington, DC 20460. In person or by telephone: Rm. 3142, CM #2, 1921 Jefferson Davis Highway, Arlington, VA, Telephone: 703–308–8715, e-mail: mendelsohn.mike@epamail.epa.gov.

SUPPLEMENTARY INFORMATION: EPA has issued the following experimental use permit: *70218–EUP–1.* Issuance. This experimental use permit allows the use of 0.825 pounds of the *Bacillus thuringiensis* subspecies *tolworthi* Cry9C protein in seeds shipped on 3,305 acres of corn to evaluate the control of the European corn borer and other lepidopteran corn pests. The program is authorized in the States of Alabama, California, Colorado, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nebraska, New York, North Carolina, Ohio, Pennsylvania, Puerto Rico, South Dakota, Tennessee, Texas, Virginia, and Wisconsin. The experimental use permit is effective from February 5, 1997 to November 30, 1997. This permit is issued with the limitation that all treated crops are destroyed or used for research purposes only.

Persons wishing to review this experimental use permit are referred to the designated contact person. Inquires concerning this permit should be directed to the person cited above. It is suggested that interested persons call before visiting the EPA office, so that the appropriate file may be made available for inspection purposes from 8 a.m. to 4 p.m., Monday through Friday, excluding legal holidays.

Authority: 7 U.S.C. 136.

List of Subjects

Environmental protection, Experimental use permits.

Dated: March 5, 1997.

Janet L. Andersen,

Director, Biopesticides and Pollution Prevention Division, Office of Pesticide Programs.

[FR Doc. 97–6518 Filed 3–13–97; 8:45 am]

BILLING CODE 6560–50–F

[FRL–5710–4]

Special Report on Environmental Endocrine Disruption: An Effects Assessment and Analysis

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of availability of risk assessment forum report.

SUMMARY: EPA is announcing the availability of the ''Special Report on Environmental Endocrine Disruption: An Effects Assessment and Analysis.'' The report provides an overview of the current state of the science for endocrine disruption. The report's major components are an introduction to the endocrine system and the endocrine disruption hypothesis; a review of potential human health and ecological risks; and an analysis section, including an overview of research needs. The report represents an interim assessment pending a more extensive review expected to be issued by the National Academy of Sciences later in 1997.

ADDRESSES: An electronic version of the report is accessible on EPA's Office of

Research and Development home page on the Internet at http://www.epa.gov/ORD. Interested parties can obtain a single copy of the report by contacting: ORD Publications Office, Technology Transfer Division, National Risk Management Research Laboratory, U.S. Environmental Protection Agency, 26 W. Martin Luther King Drive, Cincinnati, OH 45268; telephone (513) 569–7562; facsimile (513) 569–7566. Please provide your name and mailing address, and request the document by the title and EPA document number (EPA/630/R–96/012). There will be a limited number of paper copies available from the above source in mid-April. Requests will be filled on a first-come-first-served basis. After the supply is exhausted, copies of the report can be purchased from the National Technical Information Service (NTIS) by calling (703) 487–4650 or sending a facsimile to (703) 321–8547. The NTIS order number for this document is PB97-137772; Price Code A08:($31).

FOR FURTHER INFORMATION CONTACT: William Wood, Risk Assessment Forum (8103), U.S. Environmental Protection Agency, 401 M Street, S.W., Washington, DC 20460, Telephone (202) 260–6743.

SUPPLEMENTARY INFORMATION: The EPA has followed closely the recent reports dealing with the potential effects of environmental endocrine disruptors on human health and ecological well-being. EPA's Science Policy Council requested that the Risk Assessment Forum prepare a Technical Panel report that would provide an overview of the current state of the science relative to the endocrine disruption hypothesis. This report serves as an interim assessment to inform Agency risk assessors of the major findings and uncertainties relative to environmental endocrine disruption and is the basis for a position statement by EPA's Science Policy Council.

Dated: February 27, 1997.

Joseph K. Alexander,

Deputy Assistant Administrator for Science, Office of Research and Development.

[FR Doc. 97–6509 Filed 3–13–97; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL COMMUNICATIONS COMMISSION

[DA 97–386]

Auction of Wireless Communications Service (Auction No. 14)

AGENCY: Federal Communications Commission.

ACTION: Notice.

SUMMARY: The Wireless Telecommunications Bureau announced the application procedures for the upcoming WCS auction (Auction #14) in a Public Notice dated February 20, 1997. The auction is scheduled to begin April 15, 1997 and will consist of 128 licenses: two licenses in 52 Major Economic Areas in the United States and two licenses in 12 Regional Economic Area Groupings. The purpose of the public notice is to inform interested parties of the auction procedures the Commission will use in Auction #14 and the filing requirements to become an eligible bidder.

FOR FURTHER INFORMATION CONTACT: Louis Sigalos or Josh Roland, Wireless Telecommunications Bureau, at (202) 418–0660.

SUPPLEMENTARY INFORMATION: This is a summary of Public Notice DA 97–386, ''Auction of Wireless Communications Service—Auction Notice and Filing Requirements for 128 WCS Licenses Scheduled for April 15, 1997,'' released February 21, 1997. The complete text of the Public Notice is available for inspection and copying during normal business hours in the FCC Reference Center (Room 239), 1919 M Street, N.W., Washington, D.C. and also may be purchased from the Commission's copy contractor, International Transcription Service, (202) 857–3800, 2100 M Street, N.W., Suite 140, Washington, D.C. 20037.

Synopsis of the Public Notice

I. Introduction

1. *Licenses To Be Auctioned:* 128 licenses. Wireless Communications Service (''WCS'') licensees are permitted, within their assigned spectrum and geographic areas, to provide any fixed, mobile, radiolocation or broadcast-satellite use consistent with the allocation table and associated international agreements concerning spectrum allocations. The auction will consist of 2 licenses (Frequency Blocks ''A'' and ''B'') in 52 Major Economic Areas (MEAs), authorizing service on 10 MHz of spectrum, and 2 licenses (Frequency Blocks ''C'' and ''D'') in each of 12 Regional Economic Area Groupings (REAGs), authorizing service on 5 MHz of spectrum. Each frequency block encompasses the following spectrum:

Frequency Block A: 2305–2310 MHz paired with 2350–2355 MHz
Frequency Block B: 2310–2315 MHz paired with 2355–2360 MHz
Frequency Block C: 2315–2320 MHz
Frequency Block D: 2345–2350 MHz

A detailed listing of MEAs and REAGs, with their FCC market number, market description, license number, population, and upfront payment are provided in Attachment A.

2. *Auction Date:* The auction will begin on April 15, 1997. The precise schedule for bidding will be announced by public notice at least one week before the start of the auction. Unless otherwise announced, bidding will be conducted on each business day until bidding has stopped on all licenses.

3. *Auction Title:* This is the fourteenth spectrum auction the Commission has scheduled, and will be referred to as ''Auction No. 14, Wireless Communications Service.''

4. *Bidding Methodology:* Simultaneous multiple round bidding. Bidding will be by electronic means from remote locations only. Participants should note that this auction will use a round structure that is different from the procedures used in previous Commission auctions.

5. *Pre-Auction Dates*:

* Short-Form Application (FCC Form 175): March 25, 1997, 5:30 p.m. ET.
* Upfront Payments (Only Wire Transfer Accepted): April 4, 1997, 6:00 p.m. ET.
* Orders for Remote Bidding Software: April 4, 1997, 5:30 p.m. ET.
* Mock Auction: April 10, 1997.

6. *Telephone Contacts*:

* FCC National Call Center: 888-CALL-FCC (888–225–5322) (Bidder Information Packages/General Auction Information).
* FCC Technical Support Hotline: 202–414–1250.

7. *List of Attachments:*

* Attachment A: List of Licenses Offered.
* Attachment B: Electronic Filing of FCC Form 175.
* Attachment C: Guidelines for Completing FCC Form 175 and Exhibits.
* Attachment D: Summary Listing of Documents from the Commission and the Wireless Telecommunications Bureau Addressing Application of the Anti-Collusion Rules.

8. *Bidder Information Package:* More complete details about this auction will be contained in a Bidder Information Package. The Commission will provide one copy free of charge. Additional copies may be ordered at a cost of $16.00 each, including postage, payable by Visa or Master Card, or by check payable to ''Federal Communications Commission'' or ''FCC''. To place an order, please contact the FCC National Call Center at 888-CALL-FCC (888–225–5322). Bidders who do not receive their Packages within two weeks of ordering should contact the Call Center.

9. *Participation:* Those wishing to participate in the auction must submit

an FCC Form 175 short-form application. The FCC Form 175 must be completed and filed in accordance with the Commission's rules and the instructions provided in the Bidder Information Package, and must be submitted electronically no later than 5:30 p.m. ET on March 25, 1997.

10. Applicants will be required to submit an upfront payment and an FCC Remittance Advice (FCC Form 159). The upfront payment must be made in U.S. dollars by wire transfer. Payments must be received at Mellon Bank in Pittsburgh, Pennsylvania, no later than April 4, 1997 at 6:00 p.m. ET. No other form of payment will be accepted.

11. *Prohibition of Collusion:* To ensure the competitiveness of the auction process, the Commission's rules prohibit applicants for the same geographic areas from communicating with each other during the auction about bids, bidding strategies or settlements. This prohibition begins with the filing of short-form applications, and ends when winning bidders submit down payments. The prohibition does not apply where applicants enter into a bidding agreement before filing their short-form applications, and disclose the existence of the agreement in the short-form application. *See* 47 CFR Section 1.2105(c).

12. *Relevant Authority:* Prospective bidders should familiarize themselves thoroughly with the FCC's rules relating to the Wireless Communications Service contained in Part 27 of this Chapter, and rules relating to application and auction procedures, contained in Part 1, Subpart Q.

13. The specific rules applicable to WCS are contained in the Commission's *Report and Order* in *Amendment of the Commission's Rules to Establish Part 27, the Wireless Communications Service (''WCS''),* GN Docket No. 96–228, FCC 97–50 (released February 19, 1997), 62 FR 9635 (March 3, 1997). This *Report and Order* is posted on the Commission's world wide web site at http://www.fcc.gov.

14. The Terms contained in the FCC's rules, the *Report and Order,* this Public Notice, and in the Bidder Information Package are not negotiable. Prospective bidders should review these auction documents thoroughly prior to the auction to make certain that they understand all of the provisions and are willing to be bound by all of the Terms before participating in the auction.

15. The Commission may amend or supplement the information contained in this Public Notice and in the Bidder Information Package at any time. The Commission will issue public notices to convey new or supplemental information to bidders. It is the responsibility of all prospective bidders to remain current with all FCC rules and with all public notices pertaining to this auction. Copies of FCC documents, including public notices, may be obtained for a fee by calling the Commission's copy contractor, International Transcription Service, Inc., at 202–857–3800. Additionally, many documents can be retrieved from the FCC Internet node via anonymous ftp@ftp.fcc.gov or the FCC world wide web site at http://www.fcc.gov. Bidders should also note that a separate Auction's web page is available on the Commission's web site at http://www.fcc.gov/auctions.html.

16. *Bidder Alerts:* All applicants must certify under penalty of perjury on their FCC Form 175 applications that they are legally, technically, financially and otherwise qualified to hold a license, and not in default on any Commission licenses. Prospective bidders are reminded that submission of a false certification to the Commission is a serious matter that may result in severe penalties, including monetary forfeitures, license revocations, exclusion from participation in future auctions, and/or criminal prosecution.

17. The Commission makes no representations or warranties about the use of this spectrum for particular services. Applicants should be aware that an FCC auction represents an opportunity to become an FCC licensee in this service, subject to certain conditions and regulations. An FCC auction does not constitute an endorsement by the FCC of any particular services, technologies or products, nor does an FCC license constitute a guarantee of business success. Applicants should perform their individual due diligence before proceeding as they would with any new business venture.

18. As is the case with many business investment opportunities, some unscrupulous entrepreneurs may attempt to use the WCS auction to deceive and defraud unsuspecting investors. Common warning signals of fraud include the following:

* The first contact is a ''cold call'' from a telemarketer, or is made in response to an inquiry prompted by a radio or television infomercial.

* The offering materials used to invest in the venture appear to be targeted at IRA funds, for example by including all documents and papers needed for the transfer of funds maintained in IRA accounts.

* The amount of the minimum investment is less than $25,000.

* The sales representative makes verbal representations that: (a) The IRS, FTC, SEC, FCC, or other government agency has approved the investment; (b) the investment is not subject to state or federal securities laws; or (c) the investment will yield unrealistically high short-term profits. In addition, the offering materials often include copies of actual FCC releases, or quotes from FCC personnel, giving the appearance of FCC knowledge or approval of the solicitation.

19. Information about deceptive telemarketing investment schemes is available from the Federal Trade Commission (FTC) at 202–326–2222 and from the Securities and Exchange Commission (SEC) at 202–942–7040. Complaints about specific deceptive telemarketing investment schemes should be directed to the FTC, the SEC, or the National Fraud Information Center at 800–876–7060. Consumers who have concerns about specific WCS investment proposals may also call the FCC National Call Center at 888-CALL-FCC (888–225–5322).

II. Bidder Eligibility and Small Business Provisions

A. General Eligibility Criteria

20. This auction offers a total of 128 WCS licenses, with two licenses available in each of the 52 MEAs (Frequency Blocks ''A'' and ''B'') and two licenses available in each of the 12 REAGs (Frequency Blocks ''C'' and ''D''). WCS licensees will be permitted to partition their service areas into smaller geographic service areas and to disaggregate their spectrum into smaller blocks. *See* 47 CFR Section 27.15.

21. Section 27.12 of the Commission's rules sets out eligibility requirements for WCS licensees. Under Section 27.12, any entity, other than those precluded by foreign ownership restrictions set forth in Section 310 of the Communications Act of 1934, as amended, 47 U.S.C. Section 310, is eligible to hold a WCS license.

22. Prospective bidders should note that the Commission is hosting an industry forum on the WCS on February 28, 1997, at the agency's auction site located at 2 Massachusetts Avenue, N.E., Washington, D.C. Additional information regarding the forum is available on the Auction's web page of the Commission's web site, or by calling Louis Sigalos or Josh Roland of the Auctions Division of the Wireless Telecommunications Bureau at 202–418–0660.

B. Special Financial Provisions for Qualifying Small Businesses

23. Qualifying small business applicants are eligible for the special financial provision of bidding credits. *See* 47 CFR Section 27.209.

(1) Definitions of Small Businesses

24. The Commission defined the small business definitions for the WCS as:

* A ''small business'' is defined as an entity with average gross revenues not exceeding $40 million for the preceding three years.
* A ''very small business'' is defined as an entity with average gross revenues not exceeding $15 million for the preceding three years.

25. Gross revenues include all income received by an entity, whether earned or passive, before any deductions are made for costs of doing business (*e.g.*, cost of goods sold), as evidenced by audited financial statements for the relevant number of most recently completed calendar years, or, if audited financial statements were not prepared on a calendar-year basis, for the most recently completed fiscal years preceding the filing of the applicant's short-form application (FCC Form 175). If an entity was not in existence for all or part of the relevant period, gross revenues shall be evidenced by the audited financial statements of the entity's predecessor-in-interest or, if there is no identifiable predecessor-in-interest, unaudited financial statements certified by the applicant as accurate. When an applicant does not otherwise use audited financial statements, its gross revenues may be certified by its chief financial officer or its equivalent. *See* 47 CFR Section 27.210.

26. In determining whether an entity qualifies as a small business at either threshold, gross revenues of all ''controlling'' principals will be attributed to the prospective small business applicant, as well as the gross revenues of affiliates of the applicant. However, personal net worth is not included in the determination of eligibility for bidding as a small business. The term ''control'' includes both *de jure* and *de facto* control of the applicant. Typically, *de jure* control is evidenced by ownership of 50.1 percent of an entity's voting stock. *De facto* control is determined on a case-by-case basis. An entity must demonstrate at least the following indicia of control to establish that it retains *de facto* control of the applicant: (1) the entity constitutes or appoints more than 50 percent of the board of directors or partnership management committee; (2) the entity has authority to appoint, promote, demote and fire senior executives that control the day-to-day activities of the licensees; and (3) the entity plays an integral role in all major management decisions. The definition of ''affiliate'' is set forth at Section 27.210(d) of the Commission's Rules.

(2) Bidding Credits

27. The size of a WCS bidding credit depends on the annual gross revenues of the bidder and its affiliates, as averaged over the preceding three years:

* A bidder with average gross annual revenues not exceeding $40 million (a ''small business'') receives a 25-percent discount on its winning bids for WCS licenses.
* A bidder with average gross annual revenues not exceeding $15 million (a ''very small business'') receives a 35-percent discount on its winning bids for WCS licenses.

These bidding credits are not cumulative.

(3) Application Showing

28. Applicants should note that as part of their FCC Form 175 filing they will be required to file supporting documentation to establish that they satisfy the eligibility requirements to bid as a small business or very small business in this auction, and that they are subject to audits to confirm their eligibility.

(4) Unjust Enrichment

29. WCS winning bidders should note that unjust enrichment provisions apply to winning bidders who use bidding credits and subsequently assign or transfer control of their WCS licenses to an entity that does not qualify for the special financial provisions. *See* 47 CFR Section 27.209. Likewise, unjust enrichment provisions apply to any WCS licensee that received a bidding credit and subsequently partitions a portion of its license or disaggregates a portion of its spectrum to an entity that would not have qualified for such a bidding credit.

III. Pre-Auction Procedures

A. Short-Form Application (FCC Form 175)—Due March 25, 1997

30. In order to be eligible to bid in this auction, applicants must first submit an FCC Form 175 application to the Commission. This application must be submitted electronically by 5:30 p.m. ET on March 25, 1997. Late applications will not be accepted.

31. There is no application fee required when filing a FCC Form 175. However, to be eligible to bid, an applicant will have to submit an upfront payment.

(1) Electronic Filing Only

32. Applicants must file their applications electronically. Manual filing is not permitted for this auction. Generally, applicants may begin to file electronically on a 24-hour basis beginning at about the same time as release of the Bidder Information Package. All the information required to file the FCC Form 175 electronically (*i.e.*, software, help files and configuration samples) will be available over both the Internet and the FCC's Bulletin Board System (''BBS').

(2) Completion of the FCC Form 175

33. Applicants should carefully review 47 CFR Sections 1.2105 and 27.204, and must complete all items on the FCC Form 175. Instructions for completing the FCC Form 175 will be contained in the Bidder Information Package.

34. Failure to submit the required ownership information will result in dismissal of the application and loss of the ability to participate in the auction.

(3) Electronic Review of FCC Form 175

35. The FCC Form 175 review software may be used to review and print applicants' FCC Form 175 applications. In other words, applicants who file electronically may review their own completed FCC Form 175s. Applicants also have access to view other applicants' completed FCC Form 175s after the deadline for filing FCC Form 175s has passed and the Commission has issued a public notice identifying the filing status of the applicants.

B. Application Processing and Minor Corrections

36. After the deadline for filing the FCC Form 175 applications has passed, the Commission will process all timely applications to determine which are acceptable for filing, and subsequently will issue a public notice identifying: (1) Those applications accepted for filing (including FCC account numbers and the licenses for which they applied); (2) those applications rejected; and (3) those applications which have minor defects that may be corrected, and the deadline for filing such corrected applications.

37. As described more fully in our rules, after the March 25, 1997 short-form filing deadline, applicants may make only minor corrections to their FCC Form 175 applications. Applicants will not be permitted to make major modifications to their applications (e.g.,

change their license selections, change the certifying official or change control of the applicant). *See* 47 CFR Section 27.204(b).

C. Upfront Payments—Due April 4, 1997

38. In order to be eligible to bid in the auction, applicants must submit an upfront payment accompanied by an FCC Remittance Advice (FCC Form 159). All upfront payments must be received by wire transfer at Mellon Bank in Pittsburgh, Pennsylvania, by 6:00 p.m. E.T. on April 4, 1997.

39. Please note that:

*All payments must be made in U.S. dollars.

*All payments must be made by wire transfer. No other form of payment will be accepted.

*Upfront payments for Auction 14 go to a different lockbox number from the one used in previous FCC auctions, and different from the lockbox number to be used for post-auction payments.

*Failure to deliver the upfront payment by the April 4, 1997 deadline will result in dismissal of the application and disqualification from participation in the auction.

(1) Wire Transfers

40. For this auction, the Commission requires applicants to make their upfront payments by wire transfer, which experience has shown provides the greatest reliability and efficiency. Wire transfer payments must be received by 6:00 p.m. ET on April 4, 1997. To avoid untimely payments, applicants should discuss arrangements (including bank closing schedules) with their banker several days before they plan to make the wire transfer, and allow sufficient time for the transfer to be initiated and completed before the deadline. Applicants will need the following information:

ABA Routing Number: 043000261
Receiving Bank: Mellon Pittsburgh
BNF: FCC/AC—9116106
OBI Field: (Skip one space between each information item) ''AUCTIONPAY''
FCC ACCOUNT NO. (same as FCC Form 159, Block 1)
PAYMENT TYPE CODE (enter ''A30U'')
FCC CODE (same as FCC Form 159, Block 17A: ''14'')
PAYOR NAME (same as FCC Form 159, Block 3)
LOCKBOX NO. 358400

Note: The BNF and Lockbox No. are specific to the upfront payments for WCS; do not use BNF or Lockbox numbers from previous auctions.

41. Applicants must fax a completed FCC Form 159 to Mellon Bank at 412–236–5702 at least one hour before placing the order for the wire transfer (but on the same business day). On the cover sheet of the fax, write ''Wire Transfer—Auction Payment for Auction Event #14''.

(2) FCC Form 159

42. Each upfront payment must be accompanied by a completed FCC Remittance Advice (FCC Form 159). Proper completion of FCC Form 159 is critical to ensuring correct credit of upfront payments. Instructions for completing FCC Form 159 will be contained in the Bidder Information Package.

(3) Amount of Upfront Payment

43. The amount of the upfront payment required to bid on a particular license in Auction No. 14 is $0.02 per megahertz per population (MHz-pop). As noted below, a different determination is used for the Gulf of Mexico service area. The upfront payment associated with each license offered is listed in Attachment A to this Public Notice. Upfront payments, however, are not attributed to specific licenses, but instead will be translated to bidding units to define the bidder's maximum bidding eligibility.

44. Thus, an applicant does not have to make an upfront payment to cover all licenses for which it has applied. Rather, the total upfront payment defines the maximum amount of bidding units the applicant will be permitted to bid on (including standing high bids) in any single round of bidding. At a minimum, an applicant's total upfront payment must be enough to establish eligibility to bid on at least one of the licenses applied for on its FCC Form 175, or else the applicant will not be eligible to participate in the auction.

45. In calculating the upfront payment amount, an applicant should determine the maximum number of bidding units in terms of MHz-pops it may wish to bid on in any single round, and submit an upfront payment covering that number of bidding units. In this auction, the licenses authorize service over 10 MHz of spectrum for MEAs and 5 MHz of spectrum for REAGs. Thus, if an applicant wants to be eligible to bid in any single bidding round on licenses in MEAs with a maximum total population of 750,000 persons, the applicant must submit an upfront payment of $150,000 (750,000 x 10 MHz x $0.02 = $150,000). Due to the unique circumstances of the Gulf of Mexico service area (no population figure), the Commission will establish an upfront payment of $5,000 and 250,000 bidding units for each MEA license and an upfront payment of $2,500 and 125,000 bidding units for each REAG license in this area.

Note: An applicant may, on its FCC Form 175, apply for every license being offered, but its actual bidding in any round will be limited by the bidding units reflected in its upfront payment. Bidders will be required to remain active in each round of the auction on a specified percentage of bidding units reflected in their upfront payments in order to retain their current eligibility.

(4) Refunds

46. The Commission currently intends to use wire transfers for all Auction 14 refunds. To avoid delays in processing refunds, applicants should include wire transfer instructions with any refund request they file; they may also provide this information in advance by faxing it to the FCC Billings and Collections Branch, ATTN: Regina Dorsey or Linwood Jenkins, at 202–418–2843. Applicants should also note that implementation of the Debt Collection Improvement Act of 1996 requires the Commission to obtain a Taxpayer Identification Number before it can disburse refunds.

D. Auction Registration

47. No later than five business days before the auction, the Commission will issue a public notice announcing all qualified bidders for the auction. Qualified bidders are those applicants whose FCC Form 175 applications have been accepted for filing and who have timely submitted upfront payments sufficient to make them eligible to bid on at least one of the licenses for which they applied.

48. All qualified bidders are automatically registered for the auction. Registration materials will be distributed prior to the auction by two separate overnight mailings, each containing part of the confidential identification codes required to place bids. These mailings only will be sent to the contact person at the applicant address listed in the FCC Form 175.

49. Applicants who do not receive both registration mailings will not be able to submit bids. Therefore, any qualified applicant who has not received both mailings within three business days after the release of the qualified bidders public notice should contact the FCC National Call Center at 888–CALL–FCC (888–225–5322). Receipt of both registration mailings is critical to participating in the auction and each applicant is responsible for ensuring it has received all of the registration material.

Note: Qualified bidders should note that lost login codes, passwords or bidder identification numbers can only be replaced by appearing in person at the FCC Auction Headquarters located at 2 Massachusetts Avenue, N.E., Washington, D.C. 20002. Only an authorized representative or certifying official, as designated on an applicant's FCC Form 175, may appear in person with two forms of identification (one of which must be a photo identification) in order to receive replacement codes.

E. Remote Electronic Bidding Software

50. Bidding for WCS licenses is by electronic means only. Bidders must purchase remote electronic bidding software for $175.00, including shipping and handling, by April 4, 1997. (Auction software is tailored to a specific auction, so software from prior auctions will not work for Auction 14.) Information about this software and an order form will be included in the Bidder Information Package. Bidders who order remote bidding software by the ordering deadline will receive it with the registration mailings.

F. Mock Auction

51. All applicants whose FCC Form 175s have been accepted for filing will be eligible to participate in a mock auction beginning April 10, 1997. The mock auction will enable applicants to become familiar with the electronic software prior to the auction. Free demonstration software will be available for use in the mock auction. Due to different bidding procedures in the WCS auction from previous Commission auctions, participation by all bidders is strongly recommended. Details will be announced by public notice.

IV. Auction Event

52. The Commission will begin the auction on Tuesday, April 15, 1997.

A. Auction Structure

(1) Simultaneous Multiple Round Auction

53. The 128 WCS licenses will be awarded through a single, simultaneous multiple round auction. Unless otherwise announced, bids will be accepted on all licenses in each round of the auction.

(2) Activity Rule

54. In order to ensure that the auction closes within a reasonable period of time, an activity rule requires bidders to bid actively throughout the auction, rather than waiting until the end before participating. A bidder that does not satisfy the activity rule either loses bidding eligibility or uses an activity rule waiver.

55. A bidder is considered ''active'' on a license in the current round if it either is the high bidder at the end of the previous round's bidding period and does not withdraw the high bid in the current round, or submits an acceptable bid in the current round. Placing and removing a bid in the same round does not count toward activity. A bidder's activity level in a round is the sum of the bidding units associated with licenses on which the bidder is active. The minimum required activity level is expressed as a percentage of the bidder's maximum bidding eligibility and increases as the auction progresses following stage transitions.

(3) Activity Rule Waivers

56. Each bidder will be provided five activity rule waivers that may be used in any round during the course of the auction. Use of an activity rule waiver preserves the bidder's current bidding eligibility despite the bidder's activity in the current round being below the required minimum level. An activity rule waiver applies to an entire round of bidding and not to a particular license.

57. The FCC auction system assumes that bidders with insufficient activity would prefer to use an activity rule waiver (if available) rather than lose bidding eligibility. Therefore, the system will automatically apply a waiver (known as an ''automatic waiver'') at the end of any bidding period where a bidder's activity level is below the minimum required unless: (1) there are no activity rule waivers available; or (2) the bidder overrides the automatic application of a waiver by reducing eligibility.

58. A bidder with insufficient activity who wants to reduce its bidding eligibility rather than use an activity rule waiver must affirmatively override the automatic waiver mechanism during the bidding period. In this case, the bidder's eligibility is permanently reduced, and it will not be permitted to later regain its lost bidding eligibility.

59. Finally, a bidder may proactively use an activity rule waiver as a means to keep the auction open without placing a bid. If a bidder submits a proactive waiver during a bidding period in which no bids are submitted, the auction will remain open. (Note that an automatic waiver invoked in a round in which there are no new valid bids will not keep the auction open.) Thus in the later rounds of the auction, if a bidder does not intend to bid but wants to ensure that the auction does not close, it should enter a proactive waiver in place of a bid.

(4) Auction Stages

60. The auction is composed of three stages, which are each defined by an increasing activity rule. Below are the proposed activity levels for each stage of the WCS auction. The Commission reserves the discretion to alter the activity percentages.

61. *Stage One:* In each round of the first stage of the auction, a bidder desiring to maintain its current eligibility is required to be active on licenses encompassing at least 60 percent of its current bidding eligibility. Failure to maintain the requisite activity level will result in a reduction in the bidder's bidding eligibility in the next round of bidding (unless an activity rule waiver is used). During Stage One, reduced eligibility for the next round will be calculated by multiplying the current round activity by five-thirds ($5/3$).

62. *Stage Two:* In each round of the second stage, a bidder desiring to maintain its current eligibility is required to be active on 90 percent of its current bidding eligibility. During Stage Two, reduced eligibility for the next round will be calculated by multiplying the current round activity by ten-ninths ($10/9$).

63. *Stage Three:* In each round of the third stage, a bidder desiring to maintain its current eligibility is required to be active on 98 percent of its current bidding eligibility. In this final stage, reduced eligibility for the next round will be calculated by multiplying the current round activity by fifty-fortyninths ($50/49$).

64. *CAUTION:* Since activity requirements increase in each auction stage, bidders must carefully check their current activity during the bidding period of the first round following a stage transition. This is especially critical for bidders who have standing high bids and do not plan to submit new bids. In past auctions, some bidders have inadvertently lost bidding eligibility or used an activity rule waiver because they did not reverify their activity status at stage transitions. Bidders may check their activity against the required minimum activity level by using the bidding software's bidding module.

(5) Stage Transitions

65. The auction will start in Stage One. Under our general guidelines it will advance to the next stage (i.e., from Stage One to Stage Two, and from Stage Two to Stage Three) when in each of three consecutive rounds of bidding, the high bid has increased on 10 percent or less of the licenses being auctioned (as measured in bidding units). However, the Commission retains the discretion to accelerate the auction by announcement. This determination will

be based on a variety of measures of bidder activity including, but not limited to, the auction activity level, the percentages of licenses (measured in terms of activity units) on which there are new bids, the number of new bids, and the percentage increase in revenue.

(6) Auction Stopping Rules

66. Barring extraordinary circumstances, bidding will remain open on all licenses until bidding stops on every license. Thus, the auction will close for all licenses when one round passes during which no bidder submits a new acceptable bid on any license, applies a proactive waiver, or withdraws a previous high bid.

67. The Commission retains the discretion, however, to keep an auction open even if no new acceptable bids or proactive waivers are submitted, and no previous high bids are withdrawn. In this event, the effect will be the same as if a bidder had submitted a proactive waiver. Thus, the activity rule will apply as usual, and a bidder with insufficient activity will either lose bidding eligibility or use an activity rule waiver (if it has any left).

68. Further, in its discretion, the Commission reserves the right to declare that the auction will end after a specified number of additional rounds (''special stopping rule''). If the Commission invokes this special stopping rule, it will accept bids in the final round(s) only for licenses on which the high bid increased in at least one of the preceding three rounds. The Commission intends to exercise this option only in extreme circumstances, such as where the auction is proceeding very slowly, where there is minimal overall bidding activity, or where it appears likely that the auction will not close within a reasonable period of time. Before exercising this option, the Commission will probably first attempt to increase the pace of the auction by, for example, moving the auction into the next stage (where bidders would be required to maintain a higher level of bidding activity), increasing the number of bidding rounds per day, and/or increasing the amount of the minimum bid increments for the limited number of licenses where there is still a high level of bidding activity.

(7) Auction Delay, Suspension or Cancellation

69. By public notice or by announcement during the auction, the Commission may delay, suspend or cancel the auction in the event of natural disaster, technical obstacle, evidence of an auction security breach, unlawful bidding activity, administrative or weather necessity, or for any other reason that affects the fair and competitive conduct of competitive bidding. In such cases, the Commission, in its sole discretion, may elect to: resume the auction starting from the beginning of the current round; resume the auction starting from some previous round; or cancel the auction in its entirety. Network interruption may cause the Commission to delay or suspend the auction.

B. Bidding Procedures

(1) Round Structure

70. The initial bidding schedule will be announced by public notice at least one week before the start of the auction, and will be included in the registration mailings. Each bidding round contains a single bidding period followed by the release of the round results. Participants should note that the round structure for the WCS auction is a different format than the round structure used in previous Commission auctions.

71. The Commission has discretion to change the bidding schedule in order to foster an auction pace that reasonably balances speed with the bidders' need to study round results and adjust their bidding strategies. The Commission may increase or decrease the amount of time for the performance and review periods, or the number of rounds per day, depending upon the bidding activity level and other factors.

(2) Minimum Acceptable Bids

72. The Commission does not anticipate establishing a minimum opening bid for WCS licenses, but reserves the discretion to implement minimum opening bids for any license. Bidders will be informed if a minimum opening bid is imposed through a public notice released prior to the start of the auction. Once there is a standing high bid on a license, the minimum bid increment for that license will be based on the level of activity that license has received in the current and previous rounds. The Commission will release the specific methodology for calculating this increment before the start of the auction.

(3) High Bids

73. Each bid will be date-and time-stamped when it is entered into the computer system. In the event of tie bids, the Commission will identify the high bidder on the basis of the order in which bids are received by the Commission, starting with the earliest bid.

(4) Bidding

74. During a bidding period, a bidder may submit bids for as many licenses as it is eligible, as well as withdraw high bids from previous bidding periods, remove bids placed in the same bidding period, or permanently reduce eligibility. This is a change in the procedures from previous auctions. Bidders also have the option of making multiple submissions and withdrawals per each bidding period, and will not have a separate period to withdraw bids. If a bidder enters multiple bids for a license in the same round, the system takes the last bid entered as that bidder's bid for the round. A bidder withdrawing a high bid from a previous round, will be subject to the bid withdrawal payments, but a bidder removing a bid placed in the same round is not subject to the payments. Eligibility in the first round of the auction is determined by: (a) the licenses applied for on FCC Form 175 and (b) the upfront payment amount deposited. The bid submission screens will be tailored for each bidder to include only those licenses for which the bidder applied on its FCC Form 175. A bidder also has the option to tailor its bid submission screens to call up specified groups of licenses.

75. The bidding software requires each bidder to login to the FCC Auction System during the bidding period using the FCC Account Number, Bidder Identification Number, and confidential security codes provided in the registration materials. Bidders can download and print bid confirmations after they submit their bids.

(5) Bid Withdrawal

(a) Procedures

76. A high bidder that withdraws its standing high bid from a previous round is subject to the bid withdrawal payments specified in Section 27.203 of the Commission's Rules. A bidder that places a bid and removes it during the same bidding period will not be subject to a bid withdrawal payment. The procedure for withdrawing a bid and receiving a withdrawal confirmation is essentially the same as the procedure for placing a bid. To prevent strategic delays to the close of the auction, the Commission retains the discretion to limit the number of times that a bidder may re-bid on a license from which it has withdrawn a high bid.

77. If a high bid is withdrawn, the license will be offered in the next round at the second highest bid price, which may be less than, or equal to, in the case of tie bids, the amount of the withdrawn bid, without any bid increment. The

Commission will serve as a ''place holder'' on the license until a new acceptable bid is submitted on that license.

(b) Calculation

78. Generally, a bidder who withdraws a standing high bid during the course of an auction will be subject to a payment equal to the lower of (1) the difference between the net withdrawn bid and the subsequent net winning bid, or (2) the difference between the gross withdrawn bid and the subsequent gross winning bid for that license. *See* 47 CFR Section 27.203. No withdrawal payment will be assessed if the subsequent winning bid exceeds the withdrawn bid.

(6) Round Results

79. The bids placed during a bidding period are not published until the conclusion of that bidding period. After a bidding period closes, the Commission will compile reports of all bids placed, bids withdrawn, current high bids, new minimum accepted bids, and bidder eligibility status (bidding eligibility and activity rule waivers), and post the reports for public access.

80. Reports reflecting bidders' identities and bidder identification numbers will be available before and during the auction. Thus, bidders will know in advance of the auction the identities of the bidders against whom they are bidding.

(7) Auction Announcements

81. The Commission will use auction announcements to announce items such as schedule changes and stage transitions. All FCC auction announcements will be available on the FCC remote electronic bidding system, as well as the Internet and the FCC Bulletin Board System.

(8) Other Matters

82. After the short-form filing deadline, applicants may make only minor changes to their FCC Form 175 applications. For example, permissible minor changes include deletion and addition of authorized bidders (to a maximum of three) and revision of exhibits. Filers should make these changes on-line, and submit a letter to Kathleen O'Brien Ham, Chief, Auctions Division, Wireless Telecommunications Bureau, Federal Communications Commission, 2025 M Street, N.W., Room 5322, Washington, D.C., 20554 (and mail a separate copy to Josh Roland, Auctions Division), briefly summarizing the changes. Questions about other changes should be directed to the FCC Auctions Division at 202–418–0660.

V. Post-Auction Procedures

A. Down Payments and Withdrawn Bid Payments

83. After bidding has ended, the Commission will issue a public notice declaring the auction closed (''auction closing notice''), identifying the winning bids and bidders for each license, and listing withdrawn bid payments due.

84. Within ten business days after release of the auction closing notice, each winning bidder must submit sufficient funds to bring the total amount of money on deposit with the government (upfront payment less any withdrawal payments) to 20 percent of its high bids, unless it is an eligible small or very small business who elected to bid using bidding credits, then it must submit sufficient funds to bring the total amount of money on deposit with the government (upfront payment less any withdrawal payments) to 20 percent of its net winning bids (actual bids less any applicable bidding credits). *See* 47 CFR Section 1.2107(b). In addition, by the same deadline all bidders must pay any withdrawn bid amounts due under Section 1.2104(g)(1) of the Commission's Rules. Upfront payments are applied first to satisfy any outstanding bid withdrawal payments before being applied toward down payments. 47 CFR Section 1.2104(g)(2).

B. Long-Form Application (FCC Form 600)

85. Within ten business days after release of the auction closing notice, winning bidders must submit a properly completed FCC Form 600 application and required exhibits for each WCS license won through the auction. Winning small business or very small business bidders must include an exhibit demonstrating their eligibility for the small business incentives. See 47 CFR Sections 1.2107 (c) and (d). Further instructions will be provided to auction winners at the close of the auction.

86. The FCC Form 600 may be filed electronically. Alternatively, a hard copy plus required 3.5″ properly-formatted diskette copies may be sent to: FCC Form 600 Filing, Auction No. 14, Federal Communications Commission, Office of Operations, 1270 Fairfield Road, Gettysburg, PA 17325–7245.

C. Application Processing and Grant; Final Payments

87. Once a high bidder has submitted its down payment and filed an acceptable FCC Form 600 application, the Commission will release a public notice announcing acceptance of the long-form application. Parties will have five days following the public notice to file petitions to deny. Any responses to petitions to deny are due within five days. If the Commission dismisses or denies all petitions to deny, the Commission will announce by public notice that it is prepared to award a license, and the winning bidder will then have ten business days to submit the balance of its winning bid. If this payment is made, the license will be granted.

88. Winning bidders will receive further instructions and detailed payment information after the auction closes.

D. Refund of Remaining Upfront Payment Balance

89. All applicants who submitted upfront payments but were not winning bidders for any WCS license may be entitled to a refund of their remaining upfront payment balance after the conclusion of the auction. No refund will be made unless there are excess funds on deposit from that applicant after any applicable bid withdrawal payments have been paid.

90. Bidders who drop out of the auction completely may be eligible for a refund of their upfront payments before the close of the auction. However, bidders who reduce their eligibility and remain in the auction are not eligible for partial refunds of upfront payments until the close of the auction. Qualified bidders who have exhausted all their activity rule waivers, have no remaining bidding eligibility, and have not withdrawn a high bid during the auction must submit a written refund request, along with a Taxpayer Identification Number (''TIN'') and a copy of their bidding eligibility screen print, to: Federal Communications Commission, Billings and Collections Branch, Attn: Regina Dorsey or Linwood Jenkins, 1919 M Street, N.W., Room 452, Washington, D.C. 20554.

91. Bidders can also fax their request to the Billings and Collections Branch at (202) 418–2843. Once the request has been approved, a refund will be sent to the address provided on the FCC Form 159.

92. Refund processing generally takes up to two weeks to complete. Bidders with questions about refunds should contact Regina Dorsey or Linwood Jenkins at 202–418–1995.

E. Default and Disqualification

93. Any high bidder that defaults or is disqualified after the close of the

auction (*i.e.,* fails to remit the required down payment within the prescribed period of time, fails to submit a timely long-form application, fails to make full payment, or is otherwise disqualified) will be subject to the payments described in Sections 1.2104(g) and 1.2109 of the Commission's Rules. In the event that the amount of those payments cannot be determined (*i.e.* until the license has been reauctioned), the Commission can require a ''deposit'' of at least three (3) percent of the defaulted bid amount. *See* In Re C. H. PCS, Inc., BTA No. B347 Frequency Block C, Order, DA 96–1825 (released November 4, 1996). *See also* Wireless Telecommunications Bureau Will Strictly Enforce Default Payment Rules, *Public Notice,* DA 96–481 (April 4, 1996). Under certain circumstances the Commission can also reauction the license to existing or new applicants, or offer it to the other highest bidders (in descending order) at their final bids. *See* 47 CFR Sections 1.2109 (b) and (c). In addition, if a default or disqualification involves gross misconduct, misrepresentation or bad faith by an applicant, the Commission may declare the applicant and its principals ineligible to bid in future auctions, and may take any other action that it deems necessary, including institution of proceedings to revoke any existing licenses held by the applicant. *See* 47 CFR Section 1.2107(d).

F. Service and Construction Requirements

94. WCS licenses are required to provide substantial service to their service areas within ten years. Licensees failing to demonstrate that they are providing substantial service at the ten year period will be subject to forfeiture of their licenses.

Federal Communications Commission
William F. Caton,
Acting Secretary.

Attachment A—List of Licenses Offered

The following tables lists the 128 Wireless Communications Service (''WCS'') licenses to be auctioned. The licenses consist of two licenses (Frequency Blocks ''A'' and ''B'') in each of 52 Major Economic Areas (MEAs) and two licenses (Frequency Blocks ''C'' and ''D'') in each of 12 Regional Economic Area Groupings (REAGs). The MEAs and REAGs are based on the 172 Economic Area (''EAs'') developed by the Bureau of Economic Analysis of the U.S. Department of Commerce. More information regarding EAs is available on the Commission's Office of Engineering and Technology's Internet web page at: http://www.fcc.gov/oet/info/maps/bea/

SUMMARY OF LICENSES TO BE AUCTIONED: BLOCKS A AND B MAJOR ECONOMIC AREAS

MEA No.	Major economic area name	License No.	Pop.	Upfront payment
	RE01—Northeast			
ME01	Boston	WSME01A/B	8,672,944	$1,734,588.80
ME02	New York City	WSME02A/B	29,027,017	5,805,403.40
ME03	Buffalo	WSME03A/B	1,529,735	305,947.00
ME04	Philadelphia	WSME04A/B	7,942,319	1,588,463.80
	RE02—Southeast			
ME05	Washington	WSME05A/B	7,745,433	1,549,086.60
ME06	Richmond	WSME06A/B	3,897,805	779,561.00
ME07	Charlotte-G'boro-Greenville-Raleigh	WSME07A/B	9,825,342	1,965,068.40
ME08	Atlanta	WSME08A/B	7,341,931	1,468,386.20
ME09	Jacksonville	WSME09A/B	2,168,038	433,607.60
ME10	Tampa-St. Petersburg-Orlando	WSME10A/B	5,528,763	1,105,752.60
ME11	Miami	WSME11A/B	5,025,606	1,005,121.20
	RE03—Great Lakes			
ME12	Pittsburgh	WSME12A/B	4,148,373	829,674.60
ME13	Cincinnati-Dayton	WSME13A/B	4,325,459	865,091.80
ME14	Columbus	WSME14A/B	2,100,613	420,122.60
ME15	Cleveland	WSME15A/B	5,077,339	1,015,467.80
ME16	Detroit	WSME16A/B	10,041,377	2,008,275.40
ME17	Milwaukee	WSME17A/B	4,634,011	926,802.20
ME18	Chicago	WSME18A/B	12,495,510	2,499,102.00
ME19	Indianapolis	WSME19A/B	2,753,182	550,636.40
ME20	Minneapolis-St. Paul	WSME20A/B	6,018,051	1,203,610.20
ME21	Des Moines-Quad Cities	WSME21A/B	2,733,385	546,677.00
	RE04—Mississippi Valley			
ME22	Knoxville	WSME22A/B	1,364,665	272,933.00
ME23	Louisville-Lexington-Evansville	WSME23A/B	4,059,317	811,863.40
ME24	Birmingham	WSME24A/B	3,082,737	616,547.40
ME25	Nashville	WSME25A/B	2,002,283	400,456.60
ME26	Memphis-Jackson	WSME26A/B	3,850,949	770,189.80
ME27	New Orleans-Baton Rouge	WSME27A/B	4,310,367	862,073.40
ME28	Little Rock	WSME28A/B	2,309,255	461,851.00
ME29	Kansas City	WSME29A/B	2,903,432	580,686.40
ME30	St. Louis	WSME30A/B	4,436,804	887,360.80
	RE05—Central			
ME31	Houston	WSME31A/B	5,513,511	1,102,702.20
ME32	Dallas-Fort Worth	WSME32A/B	9,575,762	1,915,152.40
ME33	Denver	WSME33A/B	3,952,116	790,423.20
ME34	Omaha	WSME34A/B	1,638,440	327,688.00
ME35	Wichita	WSME35A/B	1,094,213	218,842.60
ME36	Tulsa	WSME36A/B	1,259,636	251,927.20
ME37	Oklahoma City	WSME37A/B	1,695,572	339,114.40

SUMMARY OF LICENSES TO BE AUCTIONED: BLOCKS A AND B MAJOR ECONOMIC AREAS—Continued

MEA No.	Major economic area name	License No.	Pop.	Upfront payment
ME38	San Antonio	WSME38A/B	2,944,684	588,936.80
ME39	El Paso-Albuquerque	WSME39A/B	2,114,287	422,857.40
ME40	Phoenix	WSME40A/B	3,458,935	691,787.00
	RE06—West			
ME41	Spokane-Billings	WSME41A/B	1,727,716	345,543.20
ME42	Salt Lake City	WSME42A/B	2,444,454	488,890.80
ME43	San Francisco-Oakland-San Jose	WSME43A/B	11,956,167	2,391,233.40
ME44	Los Angeles-San Diego	WSME44A/B	19,333,536	3,866,707.20
ME45	Portland	WSME45A/B	2,999,719	599,943.80
ME46	Seattle	WSME46A/B	3,990,811	798,162.20
	RE07—Alaska			
ME47	Alaska	WSME47A/B	550,043	110,008.60
	RE08—Hawaii			
ME48	Hawaii	WSME48A/B	1,108,229	221,645.80
	RE09—Guam and Northern Mariana Islands			
ME49	Guam and Northern Mariana Islands	WSME49A/B	176,000	35,200.00
	RE10—Puerto Rico and U.S. Virgin Islands			
ME50	Puerto Rico and U.S. Virgin Islands	WSME50A/B	3,623,846	724,769.20
	RE11—American Samoa			
ME51	American Samoa	WSME51A/B	47,000	9,400.00
	RE12—Gulf of Mexico			
ME52	Gulf of Mexico	WSME52A/B	0	5,000.00
Totals			252,556,719	50,516,343.80

SUMMARY OF LICENSES TO BE AUCTIONED: BLOCKS C AND D REGIONAL ECONOMIC AREA GROUPINGS

Region No.	Regional economic area grouping name	License No.	Pop.	Upfront payment
RE01	Northeast	WSRE01C/D	47,172,015	$4,717,201.50
RE02	Southeast	WSRE02C/D	41,532,918	4,153,291.80
RE03	Great Lakes	WSRE03C/D	54,327,300	5,432,730.00
RE04	Mississippi Valley	WSRE04C/D	28,319,809	2,831,980.90
RE05	Central	WSRE05C/D	33,247,156	3,324,715.60
RE06	West	WSRE06C/D	42,452,403	4,245,240.30
RE07	Alaska	WSRE07C/D	550,043	55,004.30
RE08	Hawaii	WSRE08C/D	1,108,229	110,822.90
RE09	Guam and Northern Mariana Islands	WSRE09C/D	176,000	17,600.00
RE10	Puerto Rico and U.S. Virgin Islands	WSRE10C/D	3,623,846	362,384.60
RE11	American Samoa	WSRE11C/D	47,000	4,700.00
RE12	Gulf of Mexico	WSRE12C/D	0	2,500.00
Totals			252,556,719	25,258,171.90

Attachment B—Electronic Filing of FCC Form 175

The Commission has implemented a remote access system to allow applicants to submit their FCC Form 175 applications electronically. The remote access system for initial filing of the FCC Form 175 applications will generally be available 24 hours per day beginning at approximately the same time as the release of the Bidder Information Package. FCC Form 175 applications that are filed electronically using this remote access system must be submitted and confirmed by 5:30 p.m. ET on March 25, 1997. Late applications or unconfirmed submissions of electronic data will not be accepted. The electronic filing process consists of an initial filing period and a resubmission period to make minor corrections.

Parties interested in filing FCC Form 175 applications electronically may do so via a (202) area code telephone service with no additional access charge or via a 900 number telephone service at a charge of $2.30 per minute. The first minute of connection time to the 900 number service will be at no charge.

Similarly, parties interested in reviewing FCC Form 175 applications electronically will do so via the 900 telephone service at a charge of $2.30 per minute. The first minute of connection time to the 900 number service will be at no charge.

Those applicants who wish to file their FCC Form 175 electronically or review other FCC Form 175 applications on-line will need the following hardware and software:

Hardware Requirements

* CPU: Intel 80486 or above.

* RAM: 8MB RAM (more recommended if you intend to open multiple applications).

* Hard Disk: 12MB available disk space.

* Modem: v.32bis 14.4kbps Hayes compatible modem.

* Monitor: VGA or above.

* Mouse or other pointing device.

To create backup installation disks for the FCC Form 175 Application, you will need the following:

* 1.44MB 3.5″ Floppy Drive.
* Three blank MS-DO® formatted 1.44MB floppy disks.

Software Requirements

* FCC Form 175 Application Software (available through the Internet and the FCC Bulletin Board System).
* Microsoft Windows 3.1 or Microsoft Windows for Workgroups v3.11 in an enhanced mode.

Note: The FCC Form 175 Application has not been tested in a Macintosh, OS/2, or Windows95 environment. Therefore, the FCC will not support operating systems other than Microsoft Windows 3.1 or Microsoft Windows for Workgroups v3.11 in an enhanced mode. This includes any other emulated Windows environment. If your Windows is in a networked environment, you should check with your local network administrator for any potential conflicts with the PPP (Point-to-Point Protocol) Dialer that is incorporated into the FCC Form 175 Application. This usually includes any TCP/IP installed network protocol.

The PPP Dialer that is incorporated into the FCC Form 175 Application will establish a point-to-point connection from your PC to the FCC Network. This point-to-point connection is not routed through the Internet.

Applicants who wish to file their FCC applications electronically or who wish to view other applicants' applications must first download the software from either the Internet or the FCC Bulletin Board System. Applicants must download the following compressed files to install the software: f175v10a.exe, f175v10b.exe, f175v10c.exe.

Internet Access

In order to download the compressed files from the Internet, you will need to have access to the Internet and an ftp client software as follows:

* *World Wide Web:* ftp://ftp.fcc.gov.

Once you connect to the FCC ftp server, select the following directory and download the following files:

Directory: /pub/Auctions/WCS/Auction__14/Programs.

File: f175v10a.exe, f175v10b.exe, f175v10c.exe.

* *FTP:* The following instructions are for the command line version of ftp.

1. Connect to the FCC ftp server by typing ftp ftp.fcc.gov.
2. At the user name prompt, type anonymous [Enter].
3. At the password prompt, type your Internet e-mail address [Enter].
4. To allow the file to be downloaded type: binary [Enter].
5. Change your current directory to the Programs directory by typing: cd /pub/Auctions/WCS/Auction__14/Programs [Enter].
6. Use the get command to download the files from the FCC ftp server by typing:
get f175v10a.exe [Enter]
get f175v10b.exe [Enter]
get f175v10c.exe [Enter]
7. If you wish to exit, type: bye [Enter].

* Gopher: gopher.ftp.fcc.gov or use any gopher to get to ''all the gophers in the world'' then 'U.S.' then 'DC' then 'FCC'.

Dial-In Access to the FCC Auction Bulletin Board System (BBS)

The FCC Auction Bulletin Board System provides dial-in access for the FCC Form 175 Application Software. In order to access the FCC Auction BBS, use a communications package that can handle at least xmodem protocol (e.g., pcAnyWhere, Telix, Procomm) to dial in to (202) 682–5851. Use the settings of 8 data bits, no parity and 1 stop bit (8,N,1).

* *For new users follow steps 1–5, otherwise go to step 6 in the ANSI Protocol Instructions section or the Non-ANSI Protocol Instructions section (whichever is applicable):*

1. Type New and press [Enter]. If the word ANSI is blinking, type Y for yes. If the word ANSI is not blinking, type N for No.
2. Type in your first and last name and press [Enter]. This will be your login name.
3. Type in Y and press [Enter] when asked to verify your login name.
4. Type in what you want your password to be and press [Enter].
5. Retype the password for verification and press [Enter].

**ANSI Protocol Instructions (once the account is generated):*

6. Type W for WCS Auction Files and press [Enter].
7. Type A for Auction 14 and press [Enter].
8. Type P for Programs and press [Enter].
9. Type C for Current Library and press [Enter].
10. Move the cursor to the file named f175v10a.exe and type [Control-D] for Download and press [Enter] (You may need to change the transfer protocol first—please see note below.)
11. The FCC Auction BBS will begin transferring the file. You may need to give your terminal emulation software a command to receive the file; please consult your terminal emulation software manual for instructions concerning how to do so.
12. Type X to return to the Programs menu. Repeat steps 10 and 11 to download the following files: f175v10b.exe, f175v10c.exe.
13. Type X to return to the Programs menu, then type X again. Type X to Exit and press [Enter] and continue to do so until asked if you want to Exit the BBS. Press Y for Yes when asked to verify that you want to exit.

**Non-ANSI Protocol Instructions (once the account is generated):*

6. Type W for WCS Auction Files and press [Enter].
7. Type A for Auction 14 and press [Enter].
8. Type P for Programs and press [Enter].
9. Type C for Current Library and press [Enter].
10. Type the letter next to the file named f175v10a.exe and press [Enter].
11. Type D for Download now and press [Enter] (You may need to change the transfer protocol first—please see the note below.)
12. The FCC Auction BBS will begin transferring the file. You may need to give your terminal emulation software a command to receive the file; please consult your terminal emulation software manual for instructions concerning how to do so.
13. Repeat steps 10 through 12 to download the following files: f175v10b.exe, f175v10c.exe.
14. Type X, then type X to Exit and press [Enter] and continue to do so until asked if you want to Exit the BBS. Press Y for Yes when asked to verify that you want to exit.

Note: To download files, you will need to match the transfer protocol on your BBS account to the transfer protocol set in your terminal emulation software. To set the BBS transfer protocol, return to the initial menu and type L for Library and [Enter], P for Preferences and [Enter], and P for File Transfer Protocol and [Enter]. Type the letter next to the protocol you desire and press [Enter]. You may now download files.

Extracting the FCC Form 175 Application

The FCC Form 175 Application files are downloaded in a self-extracting, compressed file format. When you have downloaded all of the compressed files for the FCC Form 175 Application, you must extract the FCC Form 175 Application from those files. To extract the software, start File Manager in the Main Program group, open the file folder where you downloaded the files, and double-click on f175v10a.exe. A message will appear listing the default directory to which the software will extract. If this directory does not exist, it will be created automatically. Press Unzip to begin extracting the software from the compressed file.

When the extraction is complete, a message will appear listing the number of files that were unzipped. Press OK and repeat the above process for the remaining compressed files (f175v10b.exe, f175v10c.exe). Be sure to extract to the same directory as the first compressed file.

Installing the FCC Form 175 Application

After you extract the software from the compressed files, you must install the FCC Form 175 Application. To install the software, start File Manager, open the file folder to which you extracted the software and double-click on setup.exe.

When the setup program begins, a screen will appear listing the default directory to which the software will install. Press the Install button, then press OK to install to the specified directory. If the directory does not exist, the setup program will create it automatically.

When the installation is complete, a message may appear asking you to restart Windows so that the changes made by the installation may take effect. Press Restart to restart Windows, or press Stay Here to restart at a later time. Do not use the FCC Form 175 Application until you restart Windows.

Creating Backup Installation Disks for the FCC Form 175 Application

To create backup installation disks for the FCC Form 175 Application, go to File Manager, open the file folder to which you extracted the software, double-click on backup.bat, and follow the instructions on the screen.

Running the FCC Form 175 Application

When the installation process is complete, you will have a new Program Manager group called FCC Form 175 Application v10 with the following icons: Configure PPP, FCC Form 175 Submit, FCC Form 175 Review, Suggestion Box, Readme, and Uninstall.

You must verify/modify the parameters in the Configure PPP program prior to establishing a PPP connection. Please consult the readme.txt file included with the software for information regarding Configure PPP.

Double-click on an icon to start the respective system.

Uninstalling the FCC Form 175 Application

To uninstall the FCC Form 175 Application, double-click on the Uninstall icon in the FCC Form 175 v10 program group. Press Start to uninstall the software.

Please note that the Uninstall program will remove ALL versions of the software located in that installation directory.

Alternatively, you may uninstall the FCC Form 175 Application by deleting the directory to which you installed the software, then switching to Program Manager and deleting the FCC Form 175 v10 icons and group.

Help

Detailed instructions for using all FCC Remote Electronic Auction System software can be found in the readme file associated with the software and in the context-sensitive help function associated with each software system.

For technical assistance in installing or using the FCC Form 175 Application, contact the FCC Technical Support Hotline at (202) 414–1250. The FCC Technical Support Hotline will be generally available Monday through Friday, from 9 a.m. to 6 p.m. ET.

Attachment C—Guidelines for Completing FCC Form 175 and Exhibits

A. FCC Form 175

Because of the significance of the Form 175 application to the auction, bidders should especially note the following:

Electronic filing only: Applicants for the WCS auction must submit their FCC Form 175 applications by means of electronic filing. Applicants should note that any attachments must be submitted in ASCII text (.TXT) format.

Items 2–5: Give a street address (not a Post Office box number) for the applicant, suitable for mail or private parcel delivery. The FCC will send all registration materials and other written communications to the applicant at this address.

Item 6: Applicants should verify that this item is pre-filled with the number ''14.'' If this item is blank or contains another number, applicants should confirm that they entered ''14'' on the initial FCC Form 175 Welcome Screen.

Item 7: Applicants must create a ten-digit FCC Account Number, which the Commission will use to identify and track applicants:

* A bidder that has a taxpayer identification number (TIN) must create this FCC account number by using its TIN, plus the prefix of ''0'' (*i.e.*, 0123456789). A TIN is either the Employer Identification Number (EIN) in the case of a business, or the Social Security Account Number (SSAN) in the case of an individual.

* If—and only if—an applicant does not have a taxpayer identification number, the applicant should use its ten-digit area code and telephone number (*i.e.*, 2025551234) on an interim basis. However, the FCC must have a TIN before it will be able to issue a license or refund upfront payments.

Each applicant must include its FCC Account Number when submitting amendments, additional information, or other correspondence or inquiries regarding its application, and must include this same number on each FCC Form 159 (FCC Remittance Advice) accompanying required auction deposits or payments.

Item 8: Applicants must indicate their legal classification. Limited liability companies or joint ventures should check the ''Other'' box and indicate their classification in the blank.

Items 9 and 10: A box does not need to be checked in Item 9 unless small business status is selected in Item 10. Applicants should be aware that they will be committed to their election choices. (Applicants are also requested to indicate their status as a rural telephone company, minority-owned business or woman-owned business as well, so the FCC can monitor its performance in promoting economic opportunities for these designated entities.) Be advised that this is the sole opportunity applicants have to elect small business status and bidding credit level (if applicable), and there is no opportunity to change the election(s) made once the short-form filing deadline passes.

* Small or very small business applicants eligible for bidding credits should check that gross revenues do not exceed the maximum dollar amount specified in the FCC rules governing the auctionable service in Item 9.

* Small or very small business applicants should enter the applicable bidding credit in Item 10: either 25 or 35 percent. Applicants should be aware that this is the sole opportunity that they will have to elect the appropriate bidding credit.

* Applicants should leave the Installment Payment Plan Type blank, as none is available for this auction.

Item 11: For each license on which they seek bidding eligibility, applicants must identify the market number in the Market No. column, and the frequency block or blocks in the Frequency Block column; frequency blocks are A and B for MEAs and C and D for REAGs. Applicants that wish to bid on all frequency blocks on all markets should check the ''ALL'' boxes in the Market No. and Frequency Block/Channel No. headings.

Applicants should identify all licenses they want to be eligible to bid on in the auction in Item 11. Be advised that there is no opportunity to change this list once the short-form filing deadline passes. The FCC Auction System will not accept bids on licenses an applicant has not applied for on its FCC Form 175.

Item 12: Applicants must list the name(s) of the person(s) (no more than three) authorized to represent them at the auction. Only those individuals listed on the FCC Form 175 will be authorized to place or withdraw bids for the applicant during the auction.

Certifications: Applicants should carefully read the list of certifications on the FCC Form 175. These certifications help to ensure a fair and competitive auction and require, among other things, disclosure to the Commission of certain information on applicant ownership and agreements or arrangements concerning the auction. Additionally, the applicant must certify that it is not in default on any Commission licenses and that it is not delinquent on any extension of credit from any federal agency. Submission of an FCC Form 175 application constitutes a representation by the certifying official that he or she is an authorized representative of the applicant, has read the form's instructions and certifications, and that the contents of the application and its attachments are true and correct. Submission of a false certification to the Commission may result in penalties, including monetary forfeitures, license forfeitures, ineligibility to participate in future auctions, and/or criminal prosecution.

Contact person: If the Commission wishes to communicate with the applicant by telephone or fax, those communications will be directed to the contact person identified on the FCC Form 175. Space is provided for a telephone number, fax number, and e-mail address. All written communications and registration information will be directed to the applicant's contact person at the address specified on the FCC Form 175. Applicants must provide a street address; no P.O. Box addresses may be used.

Completeness: Applicants must submit all information required by FCC Form 175 and by applicable rules. Failure to submit required information will result in dismissal of the application and inability to participate in the auction.

Continuing Accuracy: Each applicant is responsible for the continuing accuracy and completeness of information furnished in the FCC Form 175 and its exhibits. *See* 47 CFR Section 1.65. It is the staff's position that ten business days from a reportable change is a reasonable period of time in which applicants must amend their FCC Form 175s. Applicants are reminded that Certification (6) on FCC Form 175 includes consent to be audited.

B. Exhibits and Attachments

In addition to FCC Form 175 itself, applicants must submit additional information required by the FCC's rules. Although we do not require a particular organization or format for this information, we have developed the following guidelines that will facilitate the processing of short-form applications. We encourage applicants to submit this information using the following format. All exhibits must be in ASCII text (.TXT) format.

Exhibit A—Applicant Identity and Ownership Information: 47 CFR Section 1.2105(a)(2) requires each applicant to fully disclose the real party or parties-in-interest in an exhibit to its FCC Form 175 application. This information should provide the name, citizenship and address of all partners, if the applicant is a partnership; of a responsible officer or director, if the applicant is a corporation; of the trustee, if the applicant is a trust; or, if the applicant is none of the foregoing, list the name, address and citizenship of a principal or other responsible person.

Exhibit B—Agreements with Other Parties/Joint Bidding Arrangements: Applicants must attach an exhibit identifying all parties with whom the applicant has entered into partnerships, joint ventures, consortia or other agreements, arrangement or undertakings of any kind, relating to the licenses being auctioned, including any such agreements relating to post-auction market structure. 47 CFR Section 1.2105(a)(2)(viii).

Be aware that pursuant to Certification (4) on the FCC Form 175, the applicant certifies that it will not enter into any explicit or implicit agreements or understandings of any kind with parties not identified in the application regarding the amount to be bid, bidding strategies or the particular licenses on which the applicant will or will not bid. *See* 47 CFR Section 1.2105(a)(2)(ix). To prevent collusion, the Commission's rules generally prohibit communications during the course of the auction among applicants for the same license areas when such communications concern bids, bidding strategies, or settlements. 47 CFR Section 1.2105(c).

Exhibit C—Status as a Small or Very Small Business Applicant: Applicants claiming status as a small or very small business must attach an exhibit regarding this status.

* Small or very small business applicants must state the average gross revenues for the preceding three years for the applicant (including affiliates), as prescribed by 47 CFR Section 27.210. Certification that the average gross revenues for the preceding three years do not exceed the required limit is not sufficient.

Exhibit D—Information Requested of Designated Entities: Applicants owned by minorities or women as defined in 47 CFR Section 1.2110(b), or who are rural telephone companies, may attach an exhibit regarding this status. This information, in conjunction with the information in Item 10, will assist the Commission in monitoring the participation of designated entities in its auctions.

Exhibit E—Miscellaneous Information: Applicants wishing to submit additional information should include it in Exhibit E.

Applicants are reminded that all information required in connection with applications to participate in spectrum auctions is necessary to determine the applicants' qualifications, and as such will be available for public inspection. Required proprietary information may be redacted, or confidentiality may be requested, following the procedures set out in 47 CFR Section 0.459. Any such requests should be submitted in writing to Kathleen O'Brien Ham, Chief, Auctions Division, Wireless Telecommunications Bureau, Federal Communications Commission, 2025 M Street, N.W., Room 5322, Washington, D.C., 20554 (with a separate copy mailed to Josh Roland, Auctions Division), in which case the applicant must indicate in Exhibit E that it has filed a confidentiality request. Because the required information bears on applicants' qualifications, the Commission envisions that confidentiality requests will not be routinely granted.

Waivers: Applicants requesting waiver of any rules must submit a statement of reasons sufficient to justify the waiver sought.

Attachment D—Summary Listing of Documents From the Commission and the Wireless Telecommunications Bureau Addressing Application of the Anti-Collusion Rules

To date, discussion concerning the anti-collusion rules may be found in the following Commission and Bureau items:

Commission Decisions

Second Report and Order in PP Docket No. 93–253, FCC 94–61, 9 FCC

Rcd 2348 (1994), 59 FR 22980 (May 4, 1994), paragraphs 221–226.

Fifth Report and Order in PP Docket No. 93–253, FCC 94–178, 9 FCC Rcd 5532 (1994), 59 FR 37566 (July 22, 1994), paragraphs 91–92.

Second Memorandum Opinion and Order in PP Docket No. 93–253, FCC 94–215, 9 FCC Rcd 7245 (1994), 59 FR 44272 (Aug. 26, 1994), paragraphs 48–55.

Fourth Memorandum Opinion and Order in PP Docket No. 93–253, FCC 94–264, 9 FCC Rcd 6858 (1994), 59 FR 24947 (May 18, 1994), paragraphs 47–60.

Memorandum Opinion and Order in PP Docket No. 93–253, FCC 94–295, 9 FCC Rcd 7684 (1994), 59 FR 64159 (Dec. 13, 1994), paragraphs 8–12.

Wireless Telecommunications Bureau Decisions

Order in PP Docket No. 93–253 and MM Docket No. 94–131, DA 95–2292, (released November 3, 1995).

Public Notices

''Wireless Telecommunications Bureau Clarifies Spectrum Auction Anti-Collusion Rules,'' Public Notice, DA 95–2244 (released October 26, 1995).

''Wireless Telecommunications Bureau Provides Guidance on the Anti-Collusion Rule for D, E and F Block Bidders,'' Public Notice, DA 96–1460 (released August 28, 1996).

Letters From the Office of General Counsel and the Wireless Telecommunications Bureau

Letter to Gary M. Epstein and James H. Barker from William E. Kennard, General Counsel, Federal Communications Commission (released October 25, 1994).

Letter to Alan F. Ciamporcero from William E. Kennard, General Counsel, Federal Communications Commission (released October 25, 1996).

Letter to R Michael Senkowski from Rosalind K. Allen, Acting Chief, Commercial Radio Division, Wireless Telecommunications Bureau (released December 1, 1994).

Letter to Leonard J. Kennedy from Rosalind K. Allen, Acting Chief, Commercial Radio Division, Wireless Telecommunications Bureau (released December 14, 1994).

Letter to Jonathan D. Blake and Robert J. Rini from Kathleen O'Brien Ham, Chief, Auctions Division, Wireless Telecommunications Bureau, DA 95–2404 (released November 28, 1995).

Letter to Mark Grady from Kathleen O'Brien Ham, Chief, Auctions Division, Wireless Telecommunications Bureau, DA 96–587 (released April 16, 1996).

Letter to David L. Nace from Kathleen O'Brien Ham, Chief, Auctions Division, Wireless Telecommunications Bureau, DA 96–1566 (released September 17, 1996).

[FR Doc. 97–6418 Filed 3–13–97; 8:45 am]

BILLING CODE 6712–01–P

[MM Docket Nos. 91–221 and 87–8; 96–222; 94–150, 92–51 and 87–154]

Television Ownership Rulemaking Proceedings

AGENCY: Federal Communications Commission.

ACTION: Notice.

SUMMARY: This *Public Notice* provides an opportunity for public response to the comments filed in these related proceedings. On February 7, 1997, we received comments in each of these rulemaking proceedings regarding broadcast television ownership and broadcast television attribution rules that also address issues raised in one or more of these related proceedings but that were not filed formally in those dockets. In order to present a more complete record for comment, we have filed such comments in the appropriate dockets.

DATES: Replies are due on or before March 21, 1997.

ADDRESSES: Replies to the comments submitted in these rulemaking proceedings should be submitted to Secretary, Federal Communications Commission, Room 222, 1919 M Street, NW., Washington, DC 20554, and a copy submitted to Dorothy Conway, Federal Communications Commission, Room 234, 1919 M Street, NW., Washington, DC 20554, or via the Internet to dconway@fcc.gov.

FOR FURTHER INFORMATION CONTACT: Jane Gross at (202) 418–2130.

SUPPLEMENTARY INFORMATION:

1. In particular, the following parties filed comments in MM Docket Nos. 91–221 and 87–8 (the local television ownership proceeding). These comments also address issues in the Commission's broadcast attribution proceeding, MM Docket Nos. 94–150, 92–51 and 87–154. We will place copies of these comments in the record of MM Docket Nos. 94–150, 92–51 and 87–154: BET Holdings, Inc.; Kentuckiana Broadcasting, Inc.; Local Station Ownership Coalition; Media Access Project, Black Citizens for a Fair Media, Center for Media Education, Minority Media and Telecommunications Council, National Association for Better Broadcasting, Office of Communication of the United Church of Christ, Philadelphia Lesbian and Gay Task Force, Telecommunications Research and Action Center, Washington Area Citizens Coalition Interested in Viewers' Constitutional Rights, and Women's Institute for Freedom of the Press; Miller Broadcasting, Inc.; Montclair Communications, Inc.

2. The following party filed comments in MM Docket No. 96–222 (the national television ownership proceeding) and MM Docket Nos. 91–221 and 87–8 (the local television ownership proceeding). These comments also address issues in the Commission's broadcast attribution proceeding, MM Docket Nos. 94–150, 92–51 and 87–154. We will place copies of these comments in the record of MM Docket Nos. 94–150, 92–51 and 87–154: Post-Newsweek Stations, Inc.

3. The following party filed comments in MM Docket No. 96–222 (the national television ownership proceeding). These comments also address issues in the Commission's local television ownership proceeding, MM Docket Nos. 91–221 and 87–8. We will place copies of these comments in the record of MM Docket Nos. 94–150, 92–51 and 87–154: Cynthia L. McGillen and James P. McGillen.

4. The following party filed comments in MM Docket Nos. 94–150, 92–51 and 87–154 (the broadcast attribution proceeding). These comments also address issues in the Commission's local television ownership proceeding, MM Docket Nos. 91–221 and 87–8. We will place copies of these comments in the record of MM Docket Nos. 91–221 and 87–8: Saga Communications, Inc.

5. Copies of these comments are available for public inspection in the docket file in the Commission's Public Reference Room, room 239, 1919 M St., NW, Washington, DC 20554.

Federal Communications Commission.

William F. Caton,

Acting Secretary.

[FR Doc. 97–6422 Filed 3–13–97; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL DEPOSIT INSURANCE CORPORATION

Sunshine Act Meeting

Pursuant to the provisions of the ''Government in the Sunshine Act'' (5 U.S.C. 552b), notice is hereby given that at 10:27 a.m. on Tuesday, March 11, 1997, the Board of Directors of the Federal Deposit Insurance Corporation met in closed session to consider matters relating to the Corporation's corporate and supervisory activities.

In calling the meeting, the Board determined, on motion of Director Joseph H. Neely (Appointive), seconded by Director Eugene A. Ludwig (Comptroller of the Currency), concurred in by Mr. John F. Downey, acting in the place and stead of Director Nicolas P. Retsinas (Director, Office of Thrift Supervision), and Vice Chairman Andrew C. Hove, Jr., that Corporation business required its consideration of the matters on less than seven days' notice to the public; that no earlier notice of the meeting was practicable; that the public interest did not require consideration of the matters in a meeting open to public observation; and that the matters could be considered in a closed meeting by authority of subsections (c)(4), (c)(6), (c)(8), and (c)(9)(A)(ii) of the ''Government in the Sunshine Act'' (5 U.S.C. 552b (c)(4), (c)(6), (c)(8), and (c)(9)(A)(ii)).

The meeting was held in the Board Room of the FDIC Building located at 550 17th Street, NW., Washington, D.C.

Dated: March 11, 1997.

Federal Deposit Insurance Corporation.

Valerie J. Best,

Assistant Executive Secretary.

[FR Doc. 97–6597 Filed 3–12–97; 11:06 am]

BILLING CODE 6714–01–M

Sunshine Act Meeting

Pursuant to the provisions of the ''Government in the Sunshine Act'' (5 U.S.C. 552b), notice is hereby given that at 10:01 a.m. on Tuesday, March 11, 1997, the Board of Directors of the Federal Deposit Insurance Corporation met in open session to consider the following matters:

Memorandum and resolution re: Proposed Final Rule on Government Securities Sales Practices, 12 CFR. Part 368.

Memorandum and resolution re: Proposed Final Regarding Part 369—Prohibition Against Using Interstate Branches Primarily for Deposit Production.

In calling the meeting, the Board determined, on motion of Director Joseph H. Neely (Appointive), seconded by Mr. John F. Downey, acting in the place and stead of Director Nicolas P. Retsinas (Director, Office of Thrift Supervision), concurred in by Director Eugene A. Ludwig (Comptroller of the Currency), and Vice Chairman Andrew C. Hove, Jr., that Corporation business required its consideration of the matters on less than seven days' notice to the public; and that no notice of the meeting earlier than March 6 and March 10, 1997, was practicable.

The meeting was held in the Board Room on the sixth floor of the FDIC Building located at 550—17th Street N.W., Washington, D.C.

Dated: March 11, 1997.

Federal Deposit Insurance Corporation.

Valerie J. Best,

Assistant Executive Secretary.

[FR Doc. 97–6598 Filed 3–12–97; 11:06 am]

BILLING CODE 6714–01–M

FEDERAL FINANCIAL INSTITUTIONS EXAMINATION COUNCIL

Appraisal Subcommittee; Agency Information Collection Activities: Submission for OMB Review; Comment Request

AGENCY: Appraisal Subcommittee, Federal Financial Institutions Examination Council.

ACTION: Notice of information collection submitted to OMB for review and approval under the Paperwork Reduction Act of 1995 (Public Law 104–13 (44 U.S.C. 3506(c)(2)(A)).

SUMMARY: The ASC has submitted a collection of information, 12 CFR part 1102, subpart D, entitled, ''Description of Office, Procedures, Public Information.'' to OMB for review and approval as an extension of an existing collection of information, with no revisions. As required by the Paperwork Reduction Act of 1995, the ASC requests public comment on: (a) whether the proposed collection of information is necessary for the proper performance of the ASC's functions, including whether the information shall have practical utility; (b) the accuracy of the ASC's burden estimates; (c) ways to enhance the quality, utility and clarity of the information collected; and (d) ways to minimize the burden of collection on respondents, including the use of automated collection techniques or other forms of information technology, OMB will review this request and respond after 30 days, but before 60 days, with an OMB notice of action to the ASC that either approves or disapproves the information collection.

DATES: Written comments and recommendations on this proposal must be received on or before April 14, 1997 to receive maximum consideration.

ADDRESSES: Send comments to the OMB desk officer for the ASC: Alexander Hunt, Office of Information and Regulatory Affairs, Office of Management and Budget, New Executive Office Building, Room 3208, Washington, D.C. 20503. Please send a copy of your comment to Marc L. Weinberg, General Counsel, Appraisal Subcommittee, 2100 Pennsylvania Avenue, N.W., Suite 200; Washington, D.C. 20037, or via Internet e-mail to marcw1@asc.gov. All written comments will become a matter of public record.

FOR FURTHER INFORMATION CONTACT: Marc L. Weinberg, General Counsel, via mail to the Appraisal Subcommittee, 2100 Pennsylvania Avenue, N.W., Suite 200; Washington, D.C. 20037; Internet e-mail at marcw1@asc.gov; or telephone at (202) 634–6520, from whom copies of the information collection and supporting documents are available.

SUPPLEMENTARY INFORMATION: Request for OMB approval to extend, with no revisions, the following currently approved collection of information:

Title: ''Description of Office, Procedures, Public Information,'' 12 CFR part 1102, subpart D.

Type of Review: Extension of existing collection of information.

Form Number: None.

Frequency of Response: On occasion.

OMB Number: 3139–0006.

Affected Public: All members of the public.

Estimated Number of Respondents: 11.

Estimated Time per Response: 20 minutes.

Estimated Total Annual Burden: 3.67 hours.

Needs and uses: The information collection enables the ASC to comply with the Freedom of Information Act, as amended, (''FOIA'') 5 U.S.c. 552. It will be used by the ASC and its staff in determining whether requests for access to ASC records should be provided and whether appeals from adverse agency decisions regarding access should be granted under FOIA.

On December 10, 1996, the ASC requested comment on 12 CFR part 1102, subpart D, and specifically requested comment on: (a) whether the proposed collection of information is necessary for the proper performance of the ASC's functions, including whether the information shall have practical utility; (b) the accuracy of the ASC's burden estimates; (c) ways to enhance the quality, utility and clarity of the information collected; and (d) ways to minimize the burden of collection on respondents, including the use of automated collection techniques or other forms of information technology. No comments were received.

By the Appraisal Subcommittee of the Federal Financial Institutions Examination Council.

Dated: March 11, 1997.

Ben Henson,

Executive Director.

[FR Doc. 97–6512 Filed 3–13–97; 8:45 am]

BILLING CODE 6201–01–M

FEDERAL MARITIME COMMISSION

Notice of Agreement(s) Filed

The Commission hereby gives notice of the filing of the following agreement(s) under the Shipping Act of 1984.

Interested parties can review or obtain copies of agreements at the Washington, DC offices of the Commission, 800 North Capitol Street, N.W., Room 962. Interested parties may submit comments on an agreement to the Secretary, Federal Maritime Commission, Washington, DC 20573, within 10 days of the date this notice appears in the Federal Register.

Agreement No.: 217–011324–009.

Title: Transpacific Space Utilization Agreement.

Parties:

American President Lines, Ltd.
Kawasaki Kisen Kaisha, Ltd.
A.P. Moller-Maersk Line
Mitsui O.S.K. Lines, Ltd.
Neptune Orient Lines, Ltd.
Nippon Yusen Kaisha Line
Orient Overseas Container Line, Inc.
P&O Nedlloyd Limited
Sea-Land Service, Inc.
Hapag-Lloyd Container Linie GmbH
P&O Nedlloyd B.V.

Synopsis: The proposed modification adds Hyundai Merchant Marine, Co., Ltd. and Evergreen America Corporation as parties to the agreement.

Agreement No.: 203–011330–011.

Title: Information System Agreement.

Parties:

P&O Nedlloyd, Ltd.
American President Lines, Ltd.
Crowley Maritime Corporation
A.P. Moller-Maersk Line
Sea-Land Service, Inc.
Hapag-Lloyd Container Linie GmbH
Orient Overseas Container Line, Inc.
Lykes Bros. Steamship Co., Inc.
P&O Nedlloyd B.V.
Kawasaki Kisen Kaisha
Yang Ming Marine Transport Corp.
Mitsui O.S.K. Lines, Ltd.

Synopsis: The proposed Agreement amends Article 6 of the Agreement to authorize the Chairman and Legal Counsel for the Agreement to execute and file amendments to Article 3 of the Agreement (Membership). It also amends Article 7 to authorize telephone, telex, telefax and electronic mail polls of the Executive Committee or the full membership and to provide procedures for such polls.

Dated: March 11, 1997.

By Order of the Federal Maritime Commission.

Joseph C. Polking,

Secretary.

[FR Doc. 97–6502 Filed 3–13–97; 8:45 am]

BILLING CODE 6730–01–M

Ocean Freight Forwarder License Applicants

Notice is hereby given that the following applicants have filed with the Federal Maritime Commission applications for licenses as ocean freight forwarders pursuant to section 19 of the Shipping Act of 1984 (46 U.S.C. app. 1718 and 46 CFR part 510).

Persons knowing of any reason why any of the following applicants should not receive a license are requested to contact the Office of Freight Forwarders, Federal Maritime Commission, Washington, D.C. 20573.

Marine Air Land International Services, 819 Mitten Road, Suite 15, Burlingame, CA 94010, Miguel Angel Lopez, Sole Proprietor

Philip Island International, Inc., 1300 Newark Turnpike, Kearny, NJ 07032, Officer: Reynaldo M. Gallero, President, Estelita A. Hipolito, Vice President.

Dated: March 10, 1997.

Joseph C. Polking,

Secretary.

[FR Doc. 97–6469 Filed 3–13–97; 8:45 am]

BILLING CODE 6730–01–M

FEDERAL RESERVE SYSTEM

Sunshine Act Meeting

TIME AND DATE: 10:00 a.m., Wednesday, March 19, 1997.

PLACE: Marriner S. Eccles Federal Reserve Board Building, C Street entrance between 20th and 2lst Streets, NW., Washington, DC 20551.

STATUS: Open.

MATTERS TO BE CONSIDERED:

Summary Agenda: Because of its routine nature, no discussion of the following item is anticipated. This matter will be voted on without discussion unless a member of the Board requests that the item be moved to the discussion agenda.

1. Proposals concerning (a) guidelines for the use of volume-based pricing for Federal Reserve priced services and (b) volume-based fees for the automated clearing house (ACH) service. (This item was originally announced for an open meeting on February 26, 1997.)

2. Any items carried forward from a previously announced meeting.

Discussion Agenda: Please Note That no Discussion Items are Scheduled for This Meeting.

Note: If the item is moved from the Summary Agenda to the Discussion Agenda, discussion of the items will be recorded. Cassettes will then be available for listening in the Board's Freedom of Information Office, and copies can be ordered for $5 per cassette by calling (202) 452–3684 or by writing to: Freedom of Information Office, Board of Governors of the Federal Reserve System, Washington, DC 20551.

CONTACT PERSON FOR MORE INFORMATION: Mr. Joseph R. Coyne, Assistant to the Board; (202) 452–3204.

Dated: March 12, 1997.

Jennifer J. Johnson,

Deputy Secretary of the Board.

[FR Doc. 97–6595 Filed 3–12–97; 11:06 am]

BILLING CODE 6210–01–P

Sunshine Act Meeting

TIME AND DATE: Approximately 10:15 a.m., Wednesday, March 19, 1997, following a recess at the conclusion of the open meeting.

PLACE: Marriner S. Eccles Federal Reserve Board Building, C Street entrance between 20th and 2lst Streets, NW., Washington, DC 20551.

STATUS: Closed.

MATTERS TO BE CONSIDERED:

1. Personnel actions (appointments, promotions, assignments, reassignments, and salary actions) involving individual Federal Reserve System employees.

2. Any items carried forward from a previously announced meeting.

CONTACT PERSON FOR MORE INFORMATION: Mr. Joseph R. Coyne, Assistant to the Board; (202) 452–3204. You may call (202) 452–3207, beginning at approximately 5 p.m. two business days before this meeting, for a recorded announcement of bank and bank holding company applications scheduled for the meeting.

Dated: March 12, 1997.

Jennifer J. Johnson,

Deputy Secretary of the Board.

[FR Doc. 97–6596 Filed 3–12–97; 11:06 am]

BILLING CODE 6210–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Program Support Center; Agency Information Collection Activities: Proposed Collections; Comment Request

The Department of Health and Human Services, Program Support Center (PSC), will periodically publish summaries of proposed information collections projects and solicit public comments in compliance with the requirements of Section 3506(c)(2)(A) of the Paperwork Reduction Act of 1995. To request more information on the project or to obtain a copy of the information collection plans and instruments, call the PSC Reports Clearance Officer on (301) 443–2045.

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 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 other forms of information technology.

1. PHS Commissioned Corps Application Forms (PHS–50 and PHS–1813)—Extension

The PHS–50, Application for Appointment as a Commissioned Officer in the United States Public Health Service, is used to determine if an applicant is qualified for appointment in the Commissioned Corps of the Public Health Service (PHS). In addition, the information contained in PHS–50 establishes the basis for future assignments and benefits as a commissioned officer. Respondents: individual applicants seeking appointment as an officer in the Commissioned Corps of the PHS; Total Number of Respondents: 1,750 in calendar year 1996; Frequency of Response: once per applicant; Average Burden per Response: 1.25 hours; Estimated Annual Burden: 2,190 hours.

The PHS 1813, Reference Request for Applicants to the U.S. Public Health Service Commissioned Corps, is used to obtain reference information concerning applicants for appointment in the Commissioned Corps of the PHS.

Each applicant is required to provide four references. Respondents: persons designated by applicant; Total Number of Respondents: 7,000; Frequency of Response: once per reference source; Average Burden per Response: .25 hour; Estimated Annual Burden: 1,750 hours. Total Burden: 3,940 hours to respondents.

Send comments to Douglas F. Mortl, PSC Reports Clearance Officer, Room 17–108, Parklawn Building, 5600 Fishers Lane, Rockville, MD 20857. Written comments should be received within 60 days of this notice.

Dated: March 10, 1997.

Lynnda M. Regan,

Director, Program Support Center.

[FR Doc. 97–6523 Filed 3–13–97; 8:45 am]

BILLING CODE 4160–17–M

Centers for Disease Control and Prevention

[Announcement Number 727]

Community-Based Primary Prevention Programs to Prevent Intimate Partner Violence for a Safe America; Notice of Availability of Funds For Fiscal Year 1997

Introduction

The Centers for Disease Control and Prevention (CDC) announces the availability of fiscal year (FY) 1997 funds for cooperative agreements for minority and other community-based organizations (CBOs) to develop, implement, and evaluate community-based primary prevention programs for preventing intimate partner violence. The program will: (1) establish and expand the capacity of community-based primary prevention programs; and (2) evaluate the process and outcomes of such programs to prevent intimate partner violence among the target population(s). This program will serve two purposes:

Part I—To provide minority non-profit community-based organizations an opportunity to develop, implement, and evaluate community-based primary prevention programs to prevent intimate partner violence for the population that qualifies them for minority CBO status.

Part II—To provide other non-profit community-based organizations an opportunity to develop, implement, and evaluate community-based primary prevention programs to prevent intimate partner violence.

CDC is committed to achieving the health promotion and disease prevention objectives described in ''Healthy People 2000,'' a national activity to reduce morbidity and mortality and improve the quality of life. This announcement is related to the priority area of Violent and Abusive Behavior. (For ordering a copy of ''Healthy People 2000,'' see the Section, ''Where to Obtain Additional Information.'')

Authority

This program announcement is authorized under sections 393 and 394 of the Public Health Service Act (42 U.S.C. 280b–1a and 280b–2) as amended.

Smoke-Free Workplace

CDC strongly encourages all grant recipients to provide a smoke-free workplace and promote the non-use of all tobacco products, and Public Law 103–227, the Pro-Children Act of 1994, prohibits smoking in certain facilities that receive Federal funds in which education, library, day care, health care, and early childhood development services are provided to children.

Eligible Applicants

To be eligible for funding under this announcement, applicants must be a tax-exempt, non-profit CBO whose net earnings in no part accrue to the benefit of any private shareholder or person. Tax-exempt status is determined by the Internal Revenue Service (IRS) Code, Section 501(c)(3). Tax-exempt status may be proved by either providing a copy of the current IRS Determination Letter or a copy of the pages from the IRS' most recent list of 501(c)(3) tax-exempt organizations. Proof of tax-exempt status must be provided with the application.

Note: Effective January 1, 1996, Public Law 104–65 states that an organization described in section 501(c)(4) of the Internal Revenue Code of 1986 which engages in lobbying activities shall not be eligible to receive Federal funds constituting an award, grant (cooperative agreement), contract, loan, or any other form.

CBOs may apply under either:

Part I—Minority non-profit CBOs intending to serve predominantly racial or ethnic minority populations at risk for Intimate Partner Violence.

Part II—Other Non-profit CBOs intending to service populations at risk for Intimate Partner Violence.

Applicants may submit only one application for either Part I or Part II.

To apply as a minority non-profit CBO the applicant organization must have the following: (1) a governing board composed of more than 50 percent racial or ethnic minority members, (2) a significant number of minority individuals in key program positions (including management, administrative, and service positions), who reflect the racial and ethnic demographics, and the characteristics of the population to be served, and (3) an established record of service to a racial or ethnic minority community or communities. In addition, if the minority organization is a local affiliate of a larger organization with a national board, the larger organization must meet the same requirements listed above. If applying as a minority non-profit CBO, proof of minority status must be provided with the application. Affiliates of national organizations must provide proof of their national organization's eligibility and include with the application an original, signed letter from their chief executive officer assuring their understanding of the intent of this program announcement and the responsibilities of the recipients.

CDC will return to the sender, as non-responsive, all applications that do not contain minority status and proof of eligibility for affiliates of national organizations (for Part I only) or proof of tax-exempt status (for Part I and II).

Availability of Funds

Approximately $2.5 million is available in FY 1997 to fund up to ten awards under Parts I and II of this announcement as outlined below:

Part I—Approximately $1,250,000 is available in FY 1997 to fund up to five awards. Awards will range from $250,000–300,000 with an average award of $275,000.

Part II—Approximately $1,250,000 is available in FY 1997 to fund up to five awards. Awards will range from $250,000–300,000 with an average award of $275,000.

Projects are expected to begin on or about September 1, 1997. Awards will be made for the first 12-month budget period within a project period of up to three years. (Budget period is the interval of time into which the project period is divided for funding and reporting purposes. Project period is the total time for which a project has been programmatically approved.) Funding estimates may vary and are subject to change.

Noncompeting continuation awards for new budget periods within the approved project period will be made on the basis of satisfactory progress and the availability of funds. Proof of eligibility will be required with the noncompeting continuation application.

Applications that exceed $300,000 (including both direct and indirect costs) will be determined as ineligible and will not be accepted by CDC.

Use of Funds

Allowable Uses: Funds may be used for planning, developing, implementing, and evaluating projects. Accordingly, funds can be used to support personnel and to purchase modest amounts of hardware, and software required to implement the project. Applicants may enter into contractual agreements to purchase goods and services, or to support collaborative activities, but the applicant must retain proper stewardship over funds and retain responsibility for tasks associated with the project.

Prohibited Uses: Cooperative agreement funds for this project cannot be used for construction, renovation, the lease of passenger vehicles, the development of major software applications, or supplanting current applicant expenditures.

Prohibition on Use of CDC Funds for Certain Gun Control Activities

The Departments of Labor, Health and Human Services, and Education, and Related Agencies Appropriations Act, 1997 specifies that: ''None of the funds made available for injury prevention and control at the Centers for Disease Control and Prevention may be used to advocate or promote gun control.''

Anti-Lobbying Act requirements prohibit lobbying Congress with appropriated Federal monies. Specifically, this Act prohibits the use of Federal funds for direct or indirect communications intended or designed to influence a Member of Congress with regard to specific Federal legislation. This prohibition includes the funding and assistance of public grassroots campaigns intended or designed to influence Members of Congress with regard to specific legislation or appropriation by Congress.

In addition to the restrictions in the Anti-Lobbying Act, CDC interprets the new language in the CDC 1997 Appropriations Act to mean that CDC funds may not be spent on political action or other activities designed to affect the passage of specific Federal, State, or local legislation intended to restrict or control the purchase or use of firearms.

Background and Definitions

Background

In 1996, Understanding Violence Against Women was published by the National Research Council (NRC), underscoring the finding that significant gaps exist in understanding the extent and causes of violence against women and the impact and effectiveness of prevention programs for intimate partner violence. Little information is known about effective program efforts for racial/ethnic minority individuals. Moreover, the authors call for qualitative and quantitative efforts which: (1) recognize the influence of the broad social and cultural context in which women experience violence, and (2) individual factors, such as race, ethnicity and socioeconomic status in shaping the context and experience of violence in women's lives. The NRC further stated that, in order to reduce the amount of violence against women in the United States, the focus must be on the prevention of intimate partner violence. The NRC's call for the development of effective prevention strategies requires better understanding of the causes of violent behavior against women as well as rigorous evaluation of prevention programs.

Intimate partner violence is an urgent public health problem with devastating physical and emotional consequences for women, children, and families. Women are frequent targets of both physical and sexual assault by partners and acquaintances, as well as strangers. In 1994, almost 5,000 women in the United States died as a result of homicide. Where the Federal Bureau of Investigation (FBI) knew the relationship between the victim and the offender, 87 percent of these women were killed by someone they knew. Approximately half of these women were murdered by a spouse or someone with whom they had been intimate.

Approximately 99.9 percent of assaults on women do not result in death, but often result in physical injury or emotional distress. Researchers determined that in 1985 more than 1.8 million women were assaulted by male partners or a cohabitant. Battered women are at increased risk of depression, attempting suicide, and abusing alcohol and other drugs. It is estimated that 25 percent of all women in the United States will suffer a violent sexual attack sometime during their lives and that approximately one-third of all girls and women have been victims of violence while on a date.

Children witnessing intimate partner violence are a critical concern. Estimates vary, but children who witness intimate partner violence are more likely than those without such experiences to become victims or abusers of partners when they begin to date and develop intimate relationships. Specifically, men who witness parental violence as children are more likely to physically abuse their partners than men who did not.

Across the nation, communities are seeking to develop primary prevention programs to prevent intimate partner violence. More often than not, crisis response and the overwhelming need for direct services, as well as funding that is not specifically available for primary prevention, have hindered the development and implementation of effective and creative primary prevention programs for intimate partner violence. From those who have worked directly with and/or studied racial/ethnic populations, there is general consensus that services for the general population to prevent intimate partner violence are often not appropriate for or utilized consistently by these groups. Consequently, the racial/ethnic population, their children, and battering partners are at high risk for further violence without programs directed toward understanding and responding to their particular needs.

Definitions

Community-Based Organization (CBO) is based in the community and has established ties with community networks providing services to persons at risk for Intimate Partner Violence.

Minority Community-Based Organization (CBO) is a CBO which represents and services minority persons and whose governing body is over 50 percent racial and/or ethnic minority group members (American Indian, Alaskan Native, Asian, Pacific Islander, Black, or Hispanic populations).

Intimate partner violence (IPV) is perpetrated by a current spouse, current boyfriend/girlfriend, former spouse or former boyfriend/ girlfriend. It is divided into four categories: (1) physical violence; (2) sexual violence; (3) threats of physical or sexual violence; and (4) psychological/emotional abuse (including coercive tactics). Terms commonly used to describe intimate partner violence include domestic violence, spouse abuse, woman battering, courtship violence, sexual assault, and date and partner rape.

Target Populations are women (ages 12–45) at risk for intimate partner violence; and children (ages 0–11) who are witnesses of intimate partner violence in the home.

Scientifically-based prevention strategies are those with a sound theoretical base which have clearly articulated goals, measurable objectives, activities designed to achieve the objectives, and intended outcomes resulting from the activities. The theoretical base would include risk factors for intimate partner violence and protective factors that may mitigate or prevent intimate partner violence in the specific target population based on previous research, empirical observation, or anecdotal evidence.

Risk factor is an attribute or exposure that is associated with an increased probability of a specified outcome, such as the occurrence of intimate partner violence.

Protective factor is an attribute or exposure that is associated with a decreased probability of a specific outcome, such as the occurrence of intimate partner violence.

Primary prevention programs are those which prevent intimate partner violence from occurring in the first place. Working in conjunction with direct service programs, primary prevention programs may work by modifying and/or entirely eliminating the events, conditions, situations, or exposure to influences (risk factors) that result in the initiation of intimate partner violence and associated injuries, disabilities, and deaths as well as identifying protective factors which may prevent violence in the target group.

Coordinated response among community organizations is defined as pertinent community sectors collaborating as working partners to develop primary prevention programs in intimate partner violence for the target population(s).

Program evaluation is composed of process evaluation and outcome evaluation. Process evaluation determines the extent to which the program is implemented as intended and has been provided to the intended audience. Outcome evaluation identifies the extent to which the program was successful in achieving its goals and objectives by accomplishing its intended outcomes. It should also ensure that participants have not acquired negative outcomes.

Comparison group is one that closely resembles the applicant's community in the following areas: population size and community setting (urban/rural), ethnic composition, socioeconomic characteristics, and reported rates of intimate partner violence (number of reported cases per 1,000 women in the community, ages 12–45). Sources of data must be consistent between both the comparison and applicant communities.

Purpose

The purposes of this program for the primary prevention of intimate partner violence among the target population(s) are to:

1. Develop the capacity of programs serving the target population(s) to prevent intimate partner violence from occurring in the first place.

2. Evaluate the process and short-term outcomes of primary prevention programs to prevent intimate partner violence in the target population(s).

Programmatic Priority for Primary Prevention Programs

The following primary prevention programs and activities will be considered for funding under this announcement:

1. Strategies aimed at strengthening intimate partner violence prevention, such as child development or parenting classes which focus on intimate partner violence prevention, and support groups for children who have witnessed intimate partner violence.

2. Strategies aimed at increasing the capacity for any program that serves the target population(s), such as General Education Diploma (GED) or English as Second Language programs, job training programs, etc., to include components on intimate partner violence prevention.

3. School or community-based primary prevention programs designed to promote healthy relationships and prevent dating violence among school-aged youth, whether the youth are in school or not.

4. School or community-based programs designed to identify and assist school-aged children and adolescents who witness partner violence in the home, whether the youth are in school or not.

5. Community-based prevention programs designed to assist adolescents who have witnessed intimate partner violence and who are incarcerated.

6. Public awareness campaigns, media campaigns via billboards, Public Service Announcements (PSAs), television programs, etc., and community education specifically aimed towards the target population(s) to (1) emphasize knowledge, attitudes, beliefs and behaviors among the target population(s) that are conducive to preventing intimate partner violence; and (2) dispel misconceptions about intimate partner violence to change knowledge, attitudes, beliefs, and behaviors which promote intimate partner violence.

Note: Programs designed solely to prevent further intimate partner violence or its psychological impact proposed solely to provide services to victims will not be considered under this announcement.

Application Requirements

The applicant must provide for Part I only:

1. Evidence of current minority status. Proof of minority status, as outlined under the ‘‘Eligible Applicants’’ Section

of this announcement, must be provided in the application.

The applicant must provide for both Part I and Part II:

2. Evidence of current 501(c)(3) status. Proof of tax exempt status as outlined under the ‘‘Eligible Applicants’’ Section of this announcement, must be provided in the application.

3. A statement indicating which Priority Area(s) (1 through 6) the proposed program will address (see ‘‘Programmatic Priority for Primary Prevention Programs’’ Section of this announcement).

4. Statistical and programmatic evidence that women and families in the target population(s) community are victims of intimate partner violence and are at risk for injury and death from such violence.

5. Evidence that organizations and pertinent sectors of the community are willing working partners in a coordinated response to develop intimate partner violence primary prevention programs for the target population(s). Letters of commitment from working partners outlining capabilities, resources, and time to be allocated to the project are a requirement of this solicitation.

6. Evidence that a university, school of higher education, or organization specializing in program evaluation will assist in evaluation activities. Letters of commitment from working partners outlining capabilities, resources, and time to be allocated to the project are a requirement of this solicitation.

7. Evidence that a local intimate partner violence program that provides prevention and/or intervention services will be a part of the program planning and implementation. Letters of commitment from working partners outlining capabilities, resources, and time to be allocated to the project are a requirement of this solicitation.

8. Evidence of the existence of a full-time Program Manager and full-time Project Evaluator. These positions must be full-time and cannot be filled by part-time personnel to equal one full-time employee (FTE).

9. Evidence of the use of culturally relevant and linguistically appropriate strategies and interventions for the proposed primary prevention activities.

An affirmative response to each requirement is required (items 1–9 for Part I applicants and items 2–9 for Part II applicants) to qualify for the full review. Your response should be titled ‘‘Application Requirements’’ and must not exceed 4 pages, although, you are encouraged to reference appropriate text in, or attachments to, the application. This section should be included as the first pages of the application.

Cooperative Activities

A cooperative agreement is a legal agreement between CDC and the recipient in which CDC provides financial assistance and substantial Federal programmatic involvement with the recipient during the performance of the project.

In a cooperative agreement, CDC and the recipient of Federal funds share roles and responsibilities. In conducting activities to achieve the purpose of this program, the recipient will be responsible for the activities under A. (Recipient Activities) below, and CDC will be responsible for activities under B. (CDC Activities) below.

A. Recipient Activities must include but are not limited to the following:

1. Identify working partners from the pertinent community agencies and organizations.

2. Develop and implement the proposed activities, in conjunction with working partners, for the primary prevention of intimate partner violence among the target population(s).

3. Develop protocols and data collection instruments for evaluating the proposed primary prevention activities in conjunction with a university, school of higher education, or organization specializing in program evaluation.

4. Prepare data sets of all collected data.

5. Conduct the evaluation of the overall project in collaboration with CDC and other funded recipients.

6. Disseminate guidelines that other communities may use in implementing these primary prevention activities.

B. CDC Activities:

1. Provide consultation in further designing the primary prevention activities and evaluating the cost, process, and outcomes of the program.

2. Provide consultation on developing data collection instruments and procedures.

3. Provide consultation in establishing standardized reporting mechanisms to monitor program activities.

4. Provide up-to-date scientific and programmatic information about intimate partner violence prevention.

5. Assist in data analysis and publication of results.

6. Collaborate in compiling and disseminating results from the project evaluation.

Technical Reporting Requirements

The original and two copies of semi-annual progress reports are required of all awardees. Timelines for the semi-annual reports will be established at the time of award. An original and two copies of the Financial Status Report (FSR) are required no later than 90 days after the end of the budget period. A final progress report and FSR are due no later than 90 days after the end of the project period. All reports should be submitted to the Grants Management Branch, Procurement and Grants Office, CDC.

Application Content

Each application should be limited to 40 pages, excluding the budget/budget justification page(s) and attachments (i.e., letters of commitment, data collection form, resumes, etc.). The first pages of the application should contain the response to the ‘‘Application Requirements’’ Section and be marked ‘‘Application Requirements.’’ All material must be typewritten, double-spaced, with type no smaller than 10 characters per inch (CPI), or 12 point type, on 8.5″ × 11″ paper, with at least 1″ margins, headings, and footers, unbound and printed on one side only. Number each page clearly, and provide a complete index to the application and appendices. Do not include any spiral or bound materials or pamphlets. The applicant should provide a detailed description of first year activities and briefly describe future-year objectives and activities.

A. Executive Summary: Provide a one-page summary of the proposed program plan outlining the goals and objectives, the target population(s), the applicant’s working partners, the proposed primary prevention activities, the evaluation design, and the desired program outcomes.

B. Background and Need:

1. A description of knowledge about the dynamics of intimate partner violence in general as well as within the target population(s), including both risk and protective factors.

2. A description of the incidence of intimate partner violence and associated injury and death among the applicant’s respective target population(s).

3. A description of the applicant’s respective target population(s), including demographics by age, sex, socioeconomic status, geographic location, etc., including both quantitative and qualitative data.

4. A description of the present availability and accessibility of intimate partner violence prevention programs for the applicant’s target population(s) programs as well as existing gaps and barriers in program delivery.

5. Identify other providers and/or researchers engaged in intimate partner violence prevention projects for the

respective target population(s) in the community.

C. Access to the Target Population(s) and Collaboration with Working Partner Organizations Within the Community:

1. Provide evidence that the applicant has access to the target population(s) for implementing the proposed primary prevention activities.

2. Provide evidence of the applicant's understanding of the community and the target population(s).

3. Provide evidence that a local intimate partner violence service program that provides prevention and/or intervention services will be a part of the program planning and implementation.

4. Provide evidence that organizations and pertinent sectors of the community are willing and able working partners in a coordinated response to develop intimate partner violence primary prevention programs for the target population(s).

5. Provide evidence that a university, school of higher education, or organization specializing in program evaluation will assist in evaluation activities.

6. A description of the applicant's previous or current experience in managing and delivering intimate partner violence or similar programs to the respective target population in the community.

7. Summarize, if applicable, current or past funding received for the same or similar projects and the outcome of these efforts.

8. Provide letters of commitment and organizational charts from the working partner organizations stating the precise nature of the resources and expertise they will provide.

9. A description of how this funding will enable the working partner organizations in the community to implement and evaluate coordinated primary prevention activities in intimate partner violence for the target population(s).

10. Provide an organizational chart of how the proposed primary prevention project will be integrated into the applicant's organization.

D. Program Design and Plan of Operation for Primary Prevention Activities:

1. A description of specific program goals that remain consistent during the project, as well as short-term (year 1) objectives and long-term (years 2—3) objectives related to the project. All objectives must be time-phased, specific, measurable, and achievable.

2. A description of theoretical frameworks for the proposed primary activities that are supported by previous experience and/or research.

3. A description of how the structure of the working partnerships, as well as the specific primary prevention activities, will help achieve each of the program objectives.

4. Provide a program planning time-line indicating when each primary prevention activity will occur. For each activity, describe who will do what to implement the activity.

5. A description of how the proposed primary prevention activities represent an enhancement of existing intimate partner violence primary prevention programs or the development of new intimate partner violence primary prevention activities for achieving each of the project objectives. This should include:

a. A description of the mechanisms for developing, implementing and evaluating the proposed primary prevention activities;

b. A description of the mechanisms for linking the primary prevention activities to direct services for referral purposes, where appropriate;

c. Assurances of the target population(s) access to all proposed primary prevention activities;

d. A description of the proposed data collection instruments for the proposed primary prevention activities;

e. Empirical, theoretical or anecdotal evidence that the primary prevention activities can be effective; and

f. Provide evidence of the use of culturally and linguistically appropriate strategies for the proposed primary prevention activities.

6. For proposals where comparison groups are included:

(1) describe the comparison groups; and (2) provide evidence of access to comparison groups (letters of intent to participate).

Comparison groups are not a requirement; however, their use is strongly encouraged, wherever possible. For proposals where comparison groups are not included, demonstrate that the alternative evaluation design provides quantitative estimates for changes in knowledge, attitudes or behaviors related to intimate partner violence deriving from the primary prevention activities.

E. Project Management and Staffing:

1. A description of the proposed staffing for the project, noting existing staff as well as additional staffing needs. Applicants must provide—at a minimum—a full-time Program Manager and a full-time Project Evaluator. These positions must be full-time and cannot be filled by part-time personnel to equal one FTE. Position descriptions and curriculum vitae for each proposed staff position should be included in the application.

2. A description of the responsibilities of individual staff members including the level of effort and allocation of time for each project activity by staff position.

3. A description of the availability of staff and facilities to carry out the project.

4. Provide curriculum vitae for each key staff member and commitment of time to program activities.

5. Provide an organizational chart of the applicant's organization, including how the proposed primary prevention project will be integrated into the applicant's organization.

6. Provide evidence of key personnel involved in the project who reflect the racial and ethnic composition of the target population(s) to be served.

F. Evaluation Plan:

1. Process Evaluation

a. A description of the process of developing and implementing the proposed primary prevention activities evaluation.

b. A description of the process to develop and implement the working partner activities evaluation.

c. Identify existing gaps in programs as well as other needs in the community.

2. Outcome Evaluation

a. A description of the extent to which intended short-term outcomes have been achieved.

b. A description of the change in short-term outcomes resulting from the respective primary prevention activities from baseline to project completion.

3. The Evaluation Plan must also contain the following:

a. A description of the evaluation design, which includes a comparison group, if possible.

b. A description of methods for collecting process and outcome data, and for ensuring reliability and validity of all data collected.

c. A description of how data will be maintained (i.e., databases).

d. A description of the applicant's or proposed community working partners' capacity (facilities, computers) for collecting and managing data.

e. A description of the statistical techniques to be used for analyzing the data.

f. A description of how client confidentiality and safety will be addressed and maintained.

g. The format in which the data will be transmitted to CDC.

ASCII, Epi-Info, or SAS data sets are preferred. Protocols and core measurement instruments will be developed through collaboration among Centers for Disease Control and Prevention staff and other funded projects, where relevant.

4. Women, Racial and Ethnic Minorities. A description of the proposed plan for the inclusion of both sexes and racial and ethnic minority populations for appropriate representation.

G. Proposed Budget:

This section must include a detailed first-year budget and narrative justification with future annual projections. Budgets should include costs for travel for two project staff to attend at least two two-day meetings in Atlanta with CDC staff. For contracts contained within the application budget, applicants should name the contractor, if known; describe the services to be performed; justify the use of a third party; and provide a breakdown of and justification for the estimated costs of the contracts; the kinds of organizations or parties to be selected; the period of performance; and the method of selection.

H. Human Subjects:

This section must describe the degree to which human subjects may be at risk and the assurance that the project will be subject to initial and continuing review by the appropriate institutional review committees.

I. Attachments

Provide the following as attachments:

a. Proof of minority status (if applying for Part I, only)

b. Proof of 501(c)(3) nonprofit status.

c. A list of the members of its governing body along with their expertise in working with or providing services to the proposed target population and, for minority CBO applicants, their racial/ethnic backgrounds.

d. An organization chart of existing and proposed staff, including volunteer staff (minority CBOs should include racial/ethnic backgrounds).

e. Affiliates of national organizations must provide proof of their national organization's eligibility and include with the application an original, signed letter from their chief executive officer assuring their understanding of the intent of this program announcement and the responsibilities of recipients.

f. Evidence of collaboration/letters of support or commitment. Such collaboration may include representatives from the local community such as: health care providers, the education community, the religious community, the justice system, domestic violence program advocates, human service entities such as State child service divisions, business and civic leaders, and other pertinent sectors.

g. Independent Audit Statements from a certified public accountant must be provided for the preceding two years.

Evaluation Criteria

Applications will be reviewed by CDC staff for completeness and affirmative responsives as outlined under the previous heading, Application Requirements.

Incomplete applications and applications that are not responsive in accordance with the ''Application Requirements'' Section will be returned to the applicant without further consideration. A Special Emphasis Panel (SEP) review of responsive applications, will be conducted according to the following criteria (maximum 100 total points):

A. Background and Need: (10 Points)

The extent to which the applicant documents that the target population(s) within the community has victims of or is at risk for intimate partner violence and associated injuries and deaths; provides statistical summaries of the target population(s); documents the availability and/or lack of existing intimate partner violence primary prevention programs for the target population(s), as well as gaps in their delivery.

B. Access to the Target Population(s) and Collaboration With Working Partner Organizations in the Community: (20 Points)

The extent to which the applicant: demonstrates an understanding of and access to the target population(s); describes how funding under this program announcement will enhance and strengthen existing community intimate partner violence primary prevention efforts; includes pertinent sectors of the community (such as health care providers, the education community, the religious community, the justice system, domestic violence program advocates, human service entities such as State child service division, business and civic leaders, and other pertinent sectors) in the working partnership and have specific program responsibilities; includes letters of support from proposed community working partners regarding their specific responsibilities and commitment of time and resources; and provides assurance and establishment of culturally relevant and linguistically appropriate linkages within the target population(s) and community working partners.

C. Program Design and Plan of Operation for Primary Prevention Activities: (25 Points)

The extent to which a theoretical framework is provided outlining the rationale for the development, implementation and evaluation of proposed primary prevention activities; included appropriate comparison groups for specific proposed primary prevention activities, where feasible; goals are clearly articulated and objectives are time-phased, specific, measurable, achievable, and will achieve the desired program results; intended outcomes are theoretically or empirically justified to result from program activities; proposed data collection instruments are appropriate for collecting information relevant to the project; program planning time line is realistic and provides sufficient detail about *who* will do *what* and *when.*

The degree to which the applicant has met the CDC Policy requirements regarding the inclusion of women, ethnic, and racial groups in the proposed project. This includes:

(a) The proposed plan for the inclusion of both sexes and racial and ethnic minority populations for appropriate representation; (b) The proposed justification when representation is limited or absent; (c) A statement as to whether the design of the study is adequate to measure differences when warranted; and (d) A statement as to whether the plans for recruitment and outreach for study participants include the process of establishing partnerships with community(ies) and recognition of mutual benefits will be documented.

D. Project Management and Staffing: (20 Points)

The extent to which the applicant has experience in the management and delivery of intimate partner violence primary prevention programs at the community level; management staff and their working partners are clearly described, appropriately assigned, and have appropriate skills, experiences, and facilities, to develop, implement, and evaluate the project; and, provides evidence that a full-time Program Manager and a full-time Program Evaluator are or will be available for the entire project.

E. Evaluation Plan: (25 Points)

The degree to which the applicant includes adequate plans for a process evaluation of the attainment of proposed objectives based on the theoretical framework described in the Program Design and Plan of Operation for Primary Prevention Activities section.

F. Proposed Budget: (Not Scored)

The extent to which the budget request is clearly explained, adequately justified, reasonable, sufficient for the proposed project activities, and consistent with the intended use of the cooperative agreement funds.

G. Human Subjects: (Not Scored)

The extent to which the applicant complies with the Department of Health and Human Services Regulations (45 CFR Part 46) regarding the protection of human subjects.

Funding Preferences

In making awards, priority consideration will be given to: (1) ensuring a racial/ethnic balance, and (2) ensuring rural, urban, and national geographic distribution among the grantees.

Executive Order 12372 Review

Applications are subject to the Intergovernmental Review of Federal Programs as governed by Executive Order (E.O.) 12372. E.O. 12372 sets up a system for State and local government review of proposed Federal assistance applications. Applicants should contact their State Single Point of Contact (SPOC) as early as possible to alert them to the prospective applications and receive any necessary instructions on the State process. For proposed projects serving more than one State, the applicant is advised to contact the SPOC of each affected State. A current list of SPOCs is included in the application kit. If SPOCs have any State process recommendations on applications they should reference Announcement 727 and forward them to Ron Van Duyne, Grants Management Officer, Grants Management Branch, Procurement and Grants Office, Centers for Disease Control and Prevention (CDC), 255 East Paces Ferry Road, NE., Room 321, Mailstop E–13, Atlanta, Georgia 30305, no later than 60 days after the application deadline date. The granting agency does not guarantee to ‘‘accommodate or explain’’ State process recommendations it receives after that date.

Public Health System Reporting Requirements

This program is subject to the Public Health System Reporting Requirements. Under these requirements, all community-based nongovernmental applicants must prepare and submit the items identified below to the head of the appropriate State and/or local health agency(s) in the program area(s) that may be impacted by the proposed project no later than the receipt date of the Federal application. The appropriate State and/or local health agency is determined by the applicant. The following information must be provided:

A. A copy of the face page of the application (SF424).

B. A summary of the project that should be titled ‘‘Public Health System Impact Statement’’ (PHSIS), not to exceed one page, and include the following:

1. A description of the target population(s) to be served;

2. A summary of primary prevention activities to be implemented and evaluated;

3. A description of the coordination plans with the community working partners for developing, implementing, and evaluating the primary prevention activities.

If the State and/or local health official should desire a copy of the entire application, it may be obtained from the State Single Point of Contact (SPOC) or directly from the applicant.

Catalog of Federal Domestic Assistance Number

The Catalog of Federal Domestic Assistance number for this project is 93.262.

Other Requirements

A. Paperwork Reduction Act

Projects that involve the collection of information from 10 or more individuals and funded by this cooperative agreement program will be subject to review by the Office of Management and Budget (OMB) under the Paperwork Reduction Act.

B. Accounting System

The services of a certified public accountant licensed by the State Board of Accountancy or equivalent must be retained throughout the project period as a part of the recipient's staff or as a consultant to the recipient's accounting personnel. These services may include the design, implementation, and maintenance of an accounting system that will record receipts and expenditures of Federal funds in accordance with accounting principles, Federal regulations, and terms of the cooperative agreement.

C. Audits

Funds claimed for reimbursement under this cooperative agreement must be audited annually by an independent certified public accountant (separate and independent of the consultant referenced above or recipient's staff certified public accountant). This audit must be performed within 60 days after the end of the budget period; or at the close of an organization's fiscal year. The audit must be performed in accordance with generally accepted auditing standards (established by the American Institute of Certified Public Accountants (AICPA)), governmental auditing standards (established by the General Accounting Office (GAO)), and Office of Management and Budget (OMB) Circular A–133.

D. State and Local Requirements

Recipients must comply with prevailing State and local regulations and laws regarding the delivery of social and health services to the public and mandatory reporting of sexual or physical abuse.

E. Human Subjects

If the proposed project involves human subjects, the applicant must comply with the Department of Health and Human Services Regulations (45 CFR Part 46) regarding the protection of human subjects. Assurance must be provided to demonstrate that the project will be subject to initial and continuing review by an appropriate institutional review committee. The applicant will be responsible for providing assurance with the appropriate guidelines and form provided in the application kit.

F. Confidentiality

All personal identifying information obtained in connection with the delivery of services provided to any person in any program carried out under this cooperative agreement cannot be disclosed unless required by a law of a State or political subdivision or unless such a person provides written, voluntary informed consent.

1. Nonpersonally identifying, unlinked information, which preserves the individual's anonymity, derived from any such program may be disclosed without consent:

a. In summary, statistical, or other similar form, or

b. For clinical or research purposes.

2. Personal identifying information: Recipients of CDC funds who must obtain and retain personally identifying information as part of their CDC-approved work plan must:

a. Maintain the physical security of such records and information at all times;

b. Have procedures in place and staff trained to prevent unauthorized disclosure of client-identifying information;

c. Obtain informed client consent by explaining the risks of disclosure and the recipient's policies and procedures for preventing unauthorized disclosure;

d. Provide written assurance to this effect including copies of relevant policies; and

e. Obtain assurances of confidentiality by agencies to which referrals are made.

Assurance of compliance with these and other processes to protect the confidentiality of information will be required of all recipients. A Department of Health and Human Services (DHHS) certificate of confidentiality may be required for some projects.

G. Women, Racial and Ethnic Minorities

It is the policy of the Centers for Disease Control and Prevention (CDC) to ensure that individuals of both sexes and the various racial and ethnic groups will be included in CDC-supported research projects involving human subjects, whenever feasible and appropriate. Racial and ethnic groups are those defined in OMB Directive No. 15 and include American Indian, Alaskan Native, Asian, Pacific Islander, Black and Hispanic. Applicants shall ensure that women, racial and ethnic minority populations are appropriately represented in applications for research involving human subjects. Where a clear and compelling rationale exists that inclusion is inappropriate or not feasible, this situation must be explained as part of the application. This policy does not apply to research studies when the investigator cannot control the race, ethnicity, and/or sex of subjects. Further guidance to this policy is contained in the Federal Register, Vol. 60, No. 179, pages 47949–47951, dated Friday, September 15, 1995.

H. Capability Assessment

Some applicants may be required to participate in a fiscal Recipient Capability Assessment prior to the award of funds.

Application Submission and Deadline

The original and two copies of the application PHS Form 5161–1 (Revised 7/92, OMB Number 0937–0189) must be submitted to Joanne Wojcik, Grants Management Specialist, Grants Management Branch, Procurement and Grants Office, Centers for Disease Control and Prevention (CDC), 255 East Paces Ferry Road, NE., Room 321, Mailstop E–13, Atlanta, Georgia 30305, on or before May 20, 1997.

1. Deadline: Applications shall be considered as meeting the deadline if they are either;

a. Received on or before the deadline date; or

b. Sent on or before the deadline date and received in time for submission to the special emphasis panel review committee. For proof of timely mailing, applicants must request a legibly dated U.S. Postal Service postmark or obtain a legibly dated receipt from a commercial carrier or the U.S. Postal Service. Private metered postmarks will not be acceptable as proof of timely mailing.

2. Late Applications:

Applications that do not meet the criteria in 1.a. or 1.b. above are considered late. Late applications will not be considered in the current competition and will be returned to the applicant.

Where to Obtain Additional Information

To receive additional written information call (404) 332–4561. You will be asked to leave your name, address, and telephone number and will need to reference Announcement 727. You will receive a complete program description, information on application procedures, and application forms.

If you have questions after reviewing the contents of all the documents, business management technical assistance may be obtained from Joanne Wojcik, Grants Management Specialist, Grants Management Branch, Procurement and Grants Office, Centers for Disease Control and Prevention (CDC), 255 East Paces Ferry Road, NE., Mailstop E–13, Atlanta, GA 30305, telephone (404) 842–6535 or internet address <jcw6@cdc.gov>.

Programmatic technical assistance may be obtained from Chester L. Pogostin, D.V.M., M.P.A., Centers for Disease Control and Prevention (CDC), National Center for Injury Prevention and Control, Division of Violence Prevention, Mailstop K–60, Atlanta, Georgia 30333, telephone (770) 488–4279; Internet: clp3@cdc.gov.

This and other CDC announcements are available through the CDC homepage on the Internet. The address for the CDC homepage is http://www.cdc.gov.

CDC will not send application kits by facsimile or express mail.

Please refer to Announcement Number 727 when requesting information and submitting an application.

Potential applicants may obtain a copy of ''Healthy People 2000'' (Full report; Stock No. 017–001–00474–0) or ''Healthy People 2000'' (Summary Report; Stock No. 017–001–00473–1) referenced in the ''Introduction'' through the Superintendent of Documents, Government Printing Office, Washington D.C., 20402–9325, telephone (202) 512–1800.

Dated: March 10, 1997.

Joseph R. Carter,

Acting Associate Director for Management and Operations Centers for Disease Control and Prevention (CDC).

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[Announcement Number 731]

Research Projects for Health Promotion for Persons With Disabilities and Prevention of Secondary Conditions; Notice of Availability of Funds for Fiscal Year 1997

Introduction

The Centers for Disease Control and Prevention (CDC) announces the availability of fiscal year (FY) 1997 competitive grant and cooperative agreement funds. Part 1 of this Announcement will support research grants to: (a) Measure the magnitude of secondary conditions in specified populations of persons who have a disability; (b) determine the risk and protective factors that contribute to or avert the occurrence of secondary conditions; (c) conduct and measure the effectiveness of health promotion interventions designed to prevent secondary conditions; and/or (d) understand the prevention effectiveness and cost-effectiveness of interventions. Part 2 of this Announcement will support one cooperative agreement project to prevent the occurrence of pressure sores and other selected secondary conditions among persons with spinal cord injury.

CDC is committed to achieving the health promotion and disease prevention objectives described in ''Healthy People 2000,'' a national activity to reduce morbidity and mortality and improve the quality of life. This Announcement is related to the Healthy People 2000 category of Preventive Services. (For ordering a copy of ''Healthy People 2000,'' see the section Where to Obtain Additional Information.)

Authority

This program is authorized by Section 301(a) (42 U.S.C. 241(a)) and Section 317 (42 U.S.C. 247b) of the Public Health Service Act, as amended.

Smoke-Free Workplace

CDC strongly encourages all grant recipients to provide a smoke-free workplace and promote the non-use of all tobacco products. Public Law 103–227, the Pro-Children Act of 1994 prohibits smoking in certain facilities that receive Federal funds in which education, library, day care, health care, and early childhood development services are provided to children.

Eligible Applicants

Eligible applicants for this program are public and private non-profit entities, including universities; university-affiliated systems including not-for-profit medical centers; research institutions and rehabilitation hospitals; State health departments and other related State government agencies; disability service groups such as advocacy and voluntary organizations and independent living centers; and federally recognized Indian Tribal Governments.

Note: An organization described in section 501(c)(4) of the Internal Revenue Code of 1986 which engages in lobbying activities shall not be eligible to receive Federal funds constituting an award, grant, contract, loan, or any other form.

Availability of Funds

This Announcement has two separate components as noted in the INTRODUCTION section. Under Part 1, it is anticipated that approximately $1,800,000 will be available in FY 1997 to support 6 to 8 research grant projects, with an expected range of awards from $220,000 to $280,000 each. Under Part 2, it is estimated that approximately $250,000 will be available in FY 1997 to support one cooperative agreement to prevent the occurrence of pressure sores and other selected secondary conditions among persons with spinal cord injury. Awards are expected to be made on or before August 1, 1997, for a twelve-month budget period within a project period of up to three years. Funding estimates are subject to change, including funds to be awarded in continuation years based on documented progress toward objectives, the quality of continuation year work plans, evidence of cost-sharing, and the availability of funds.

This program has no statutory matching requirement. However, applicants should document their financial support for a portion of project costs, such as salaries for key staff and tangible contributions by collaborating agencies. Applicants should also demonstrate their capacity to increase cost-sharing over time, and identify other funding sources to assist in project activities.

Use of Funds

Grant funds may be used to support personnel services, supplies, equipment, travel, subcontracts, and other services directly related to project activities consistent with the approved scope of work. Project funds may not be used to supplant other available applicant or collaborating agency funds, for construction, for lease or purchase of facilities or space, or for patient care. Project funds may not be used for individualized preventive measures (direct patient support) such as for wheelchairs, medical appliances, or assistive technology unless specifically approved by the funding agency.

Purpose

The purpose of grant awards under Part 1 is to develop better understanding of the secondary conditions that occur among prescribed groups of persons with disabilities. These awards will allow grantees to measure the risk factors and protective factors for preventing secondary conditions, and to assess the cost- and prevention-effectiveness of interventions targeted to the needs of persons with disabilities.

The purpose of the Part 2 cooperative agreement award is to design, conduct, and report the findings of a model project to prevent pressure sores and other selected secondary conditions among persons with spinal cord injury. This project should explore the feasibility of a home-based intervention; e.g., a public health nurse visitation program addressing medical, social, and environmental factors associated with the development of pressure sores and other selected secondary conditions.

Projects receiving funds for either Part 1 or Part 2 are expected to design, document, and publish the results of their research in a manner that promotes generalizability so that academic institutions, State and local agencies, disabilities service programs, and other organizations concerned with public health and health promotion programs for persons with disabilities and rehabilitation can benefit. Project activities must provide evidence that all project programs will involve and be accessible to persons with disabilities.

Background—General

The CDC Office on Disability and Health (proposed, current name-Disabilities Prevention Program) has provided grant funds to universities, rehabilitation hospitals, and State agencies since 1988 to increase understanding of the disabling process and conduct research to prevent secondary conditions. Those research grants have focused on the frequency, severity, cost, and significance of a specific, or a range of secondary conditions associated with a prescribed primary disability (e.g., spinal cord injury, traumatic brain injury, fetal alcohol syndrome, cerebral palsy, and the late effects of polio).

Background for Part 1

Part 1 of the research emanating from this Announcement is designed to examine, understand, and document the participation of persons with disabilities within their social environment as related to a particular disability domain. Disability domains are categories of activities that individuals perform in everyday life. Applicants should propose grant activities in at least one of the following disability domains: (1) Mobility (locomotion); (2) personal care/home management; (3) communication; and (4) learning. Descriptions and examples within these disability domains are as follows:

1. *Mobility* (locomotion) refers to an individual's ability to perform distinctive activities associated with moving; both himself and objects, from place to place. Examples of underlying conditions or diagnoses include spinal cord injury, cerebral palsy, arthritis, lower limb loss, blindness, or stroke. Secondary conditions may include urinary tract infections, cardiovascular deficit due to sedentary lifestyle, pressure sores, results from falls, bowel obstruction, dependence on assistive devices and its economic impact, lack of access to medical care, and social isolation.

2. *Personal Care/Home Management* refers to an individual's ability to perform basic self-care activities such as feeding, bladder and bowel care, personal hygiene, dressing, financial management, and homemaking. Examples of underlying conditions or diagnoses include asthma, arthritis, stroke, osteoporosis, paraplegia, or multiple sclerosis. Secondary conditions may include lack of physical fitness, incontinence, weight gain, poor nutrition, and emotional dependence.

3. *Communication* refers to an individual's ability to generate and express messages, and to receive and understand messages. Examples of underlying conditions or diagnoses include cerebral palsy, deafness, aphasia from varied pathology, or congenital speech impediments. Secondary conditions may include family dysfunction, isolation, and constraints and barriers in employment opportunity.

4. *Learning* refers to an individual's ability to profit from daily experiences,

and includes aspects of receiving, processing, remembering, and using information. Examples of underlying conditions or diagnoses include mental retardation, spina bifida, fetal alcohol syndrome, or traumatic brain injury. Secondary conditions may include depression, behavioral problems, increased family stress, and poor academic and vocational performance.

Note that the examples listed above are illustrative, and not intended to be exhaustive; several secondary conditions may apply to more than one disability domain. Because of limited funds and other resources available, this Announcement does not include disabilities created by psychiatric diagnoses, although mental health issues may be appropriately included as secondary conditions.

The model of health promotion used for Part 1 of this Announcement assumes a goal of promoting health and preventing secondary conditions among persons with disabilities. The basic conceptual model is represented by the International Classification of Impairments, Disabilities, and Handicaps (ICIDH). Revisions proposed to the ICIDH framework include definitions and concepts consistent with a broader perspective of the disabling process. Of particular importance is the utility of this paradigm for data collection, given its classification of disabilities and related variables. Definitions referenced in this framework are presented below:

1. *Participation* refers to the product of the interactions between the individual and the environment, and is delineated by the outcomes of that interaction. The intent of this dimension is to document the nature and extent of a person's involvement in life activities. This dimension is broadly analogous to the term ''Handicap'' in the ICIDH (World Health Organization, 1980) model and the term ''Disability'' in the Institute of Medicine (IOM, 1991) model.

2. *Environment* refers to the physical, social, and cultural contexts in which the individual acts. Elements of the environment create the backdrop for the individual's participation, as facilitators or hindrances.

3. *Impairment* refers to loss or abnormality in a body structure, organ, or system as a consequence of disease, injury, or congenital disorder. In the context of health experience, an impairment is any loss or abnormality of psychological, physiological, or anatomical structure or function.

4. *Disability* refers to any restriction or lack of ability to carry out simple or complex activities of everyday life. It is the manifestation of an underlying impairment, but may vary by age or developmental stage.

5. *Health Promotion* is the effort to educate persons with a disability about the relationship between protective and risk factors and secondary conditions, and to increase behaviors consistent with a healthy lifestyle. Health promotion concerns those behaviors that affect health status and are under the direct control of persons who have a disability.

6. *Secondary Conditions* are those physical, medical, cognitive, emotional, or psychosocial conditions, (to which persons with a disability are more vulnerable by virtue of an underlying condition), including adverse outcomes in health, wellness, participation, and quality of life.

7. *Protective Factors* are biological, environmental (social and physical), and lifestyle or behavioral characteristics that reduce or mitigate the risk for adverse health outcomes, enhance coping skills, induce a positive mediating influence against the effects of secondary conditions, and/or promote health.

8. *Risk Factors* are biological, environmental (social and physical), and lifestyle or behavioral characteristics that increase the risk for adverse health outcomes. Identifying such factors can contribute to determining a course of action during the disabling process, including the development of preventive interventions.

9. *Quality of Life* is associated with the concept of well-being, encompassing both physical and psychosocial determinants. Components of quality of life include performance of social roles, physical status, emotional status, social interactions, economic status, and self-perceived or subjective health status.

Background for Part 2

Pressure sores are the most common and costly complication among persons with spinal cord injury. There are an estimated 200,000 persons with spinal cord injury in the United States. Almost all persons with spinal cord injury will experience at least one pressure sore in their lifetime. Although estimates vary, the prevalence of pressure sores may be more than 20 percent among persons with spinal cord injury. One study showed that the average institutional costs (for acute care and rehabilitation hospitalizations) for pressure sores were $92,723. The overall cost of hospital stays and economic loss due to pressure sores may be over $6 billion each year (regardless of underlying condition).

Pressure sores are lesions caused by unrelieved pressure, trauma, friction, and/or moisture which damages the skin and then the underlying tissues. Much is known about the factors associated with pressure sore development and treating pressure sores once they occur. Pressure sores are also considered the secondary condition most amenable to prevention among persons with spinal cord injury. As part of rehabilitation, persons with spinal cord injury are taught how to care for their skin and how to prevent pressure sores once they leave the hospital environment and return home. Despite this training, persons with spinal cord injury continue to experience pressure sores.

Despite what is known about the factors associated with the development of pressure sores, little is known about why persons with spinal cord injury do not optimize skin care and other behaviors to prevent pressure sores from occurring. One study, conducted by the Arkansas State Spinal Cord Commission, found initial success with an in-home education program in which the incidence of pressure sores decreased by 19 percent. In long-term follow-up, however, the incidence of pressure sores actually increased among program participants.

Because few such programs have been developed and implemented, little is known about community-based prevention programs for the prevention of pressure sores. The emphasis here is prevention and early intervention rather than treatment. Recognizing that individual situations vary, assessment of risk for developing pressure sores and education for prevention should be done in the context of individual needs, strengths, and environment. Applicants should use available information on pressure sore prevention in the post-rehabilitation, community setting to develop a model program and plan, and implement and evaluate the feasibility of doing a home-visitation program.

Program Requirements for Part 1

Applicants must design, develop, and evaluate health promotion programs or conduct an epidemiologic study that will contribute to a national information base for the prevention of secondary conditions. CDC has indicated the following four areas for emphasis under Part 1 of this Announcement and applicants must develop their proposals to respond to one of these four areas.

1. Development of reliable and valid measurements to assess Participation among persons with disabilities, and characteristics of the Environment which influence that participation.

Applicants may choose to work across disability domains. These are evolving dimensions to the ICIDH framework to replace the ''Handicap'' dimension. There is a pressing need to clarify and understand these dimensions and characteristics. There is a benefit in having the capacity to assess empirically the influence of environment on participation in life activities for persons with disabilities. The need to assess these dimensions to improve the health status, expand research emphasis, and develop policy regarding persons with disabilities is both timely and critical.

2. Work toward measuring the cost-effectiveness of one or more intervention strategy(ies) designed to minimize the effects of or prevent selected secondary condition(s). In order to guide the conduct of cost-utility and cost-effectiveness analysis in federally funded programs, the PHS recently developed consensus-based Cost-Effectiveness Recommendations which have direct applicability to research on the prevalence and consequences of secondary conditions. Applying cost-utility and/or cost-effectiveness analytic techniques improves the basis for the allocation of health care resources across a broad range of secondary conditions among many preventive, therapeutic, rehabilitative, and public health interventions. The PHS Cost-Effectiveness Recommendations emphasize standardization of methods, adoption of the societal perspective in conducting analyses, and use of the summary measure known as the ''quality-adjusted life year'' (QALY) as a comparable metric for recording the effects of different interventions. Thus, there is both an opportunity and a need to establish basic prevention strategies that focus on common secondary conditions, and to apply methods that evaluate their comparative cost-effectiveness, so that successful strategies and approaches can be generalized and replicated in other settings. Reference citations for these published recommendations are presented in the Bibliography, which is an attachment to this Announcement.

3. Identification and measurement of protective factors and risk factors within a disability domain, and measurement of the effectiveness of preventive interventions that focus on an identified age group that includes: (a) Children; (b) youth; and/or (c) older adults. Given the paucity of research on secondary conditions generally, there is even less data available on specific age groups within the population which may be even more susceptible to developing secondary conditions.

4. Identification and measurement of protective factors and risk factors within a disability domain, and measurement of the effectiveness of preventive interventions among specified populations that include women and/or ethnic minority groups, or a combination of the two. Among persons with disabilities, susceptibility to secondary conditions may be higher in particular populations. Emphasis should be given to populations considered to be at greatest risk.

Program Requirements for Part 2

Applicants must develop proposals to address pressure sores and other selected secondary conditions among persons with spinal cord injury. The model program proposed should be home-based and able to collect information on and address medical, social, and environmental factors associated with the development and progression of pressure sores and other selected secondary conditions.

Applicants should address the development, implementation, and appropriate evaluation of a home-based model project to prevent pressure sores and other selected secondary conditions among persons with spinal cord injury. The emphasis of the project should be to assess the feasibility of the program, including access to persons with spinal cord injury, recruiting and retaining study participants, logistical management and support of a home-based visitation program, and educational materials for the prevention of pressure sores and other selected secondary conditions. Applicants should consider addressing persons with spinal cord injury at greatest risk of secondary conditions, including persons of low socioeconomic status or persons considered medically underserved. A close working relationship between the recipient and CDC is expected.

Applicants for Part 2 should develop a prevention program based on a public health nurse, home-visit model. The project should include the following elements:

1. Collect, compile, and analyze information relevant to the prevention of pressure sores and other selected secondary conditions among persons with spinal cord injury;

2. Develop a program consisting of the following phases:

a. A twelve month planning/recruitment phase where the recipient explores existing materials relevant to the program, identifies and selects other secondary conditions to be addressed, identifies educational materials to be used for the prevention of pressure sores and the other identified secondary conditions, hires and trains home visitation staff, and identifies and recruits study participants.

b. An implementation phase where the home visitation project is implemented (data collection, education) in the target population.

c. A monitoring phase where the intervention project continues with the monitoring of the intervention, the occurrence of pressure sores, the occurrence of other secondary conditions, and associated risk factors.

d. A follow-up phase for continued monitoring and evaluation.

3. Develop and implement the methods (both scientific and operational) for collecting data to assess the impact of the intervention.

4. Determine how data will be maintained including format and databases, and confidentiality protections.

5. Obtain the necessary clearances and agreements to proceed with all aspects of the proposed project, including appropriate human subjects clearances and agreements with other organizations and individuals needed to complete the project. This specifically includes working with CDC to obtain human subjects clearances and approval for data collection activities.

6. Identify or develop, and pilot test data collection instruments.

7. Establish baseline rates for pressure sores or other secondary conditions within the target group. Identify potential data sources to provide baseline information or data for comparison.

8. Monitor progress toward achievement of project goals through the use of realistic, measurable, time-oriented objectives for all phases of the project.

9. Develop collaborative relationships with voluntary, community-based public and private organizations addressing issues important to persons with spinal cord injury. These could include centers for independent living, and local chapters of the Paralyzed Veterans of America and the National Spinal Cord Injury Association.

Cooperative Agreement Activities (Part 2 Only)

In conducting activities to achieve the purposes of Part 2 of this Announcement, the recipient shall be responsible for activities listed under A. (Recipient Activities), and CDC shall be responsible for activities listed under B. (CDC Activities):

A. *Recipient Activities:*

1. Collect, compile, and analyze information relevant to the prevention of pressure sores and other selected secondary conditions among persons with spinal cord injury.

2. Develop a home-visit prevention model program consistent with the public health nurse approach and framework.

3. Implement the home visitation project (data collection, education) in the target population.

4. Monitor the intervention, the occurrence of pressure sores, the occurrence of other secondary conditions, and associated risk factors.

5. Provide for ongoing project evaluation.

6. Provide for final dissemination of the products of the research including conclusions and recommendations suitable for broad replication in other prevention settings.

B. *CDC Activities:*

1. Provide technical consultation on: existing materials relevant to the program (educational materials to be used for the prevention of pressure sores and the other identified secondary conditions), the selection of other secondary conditions to be targeted, and the identification and recruitment of study participants.

2. Participate in program planning and development.

3. Participate in the development of the evaluation aspects of the project.

4. Provide consultation in the development of data collection instruments, methods, and procedures.

Application Contents—Part 1

1. Describe the applicant organization's current activities that relate to the prevention of secondary conditions. Define the populations included and the scope of any current research, specific health promotion or training interventions, and the outcomes and use made of such interventions and services.

2. Provide the rationale and basis for both the selection of a disability domain(s) and the selected area for emphasis for the proposed research agenda.

3. Discuss how the applicant organization is in an advantageous position to conduct the proposed project, and describe the special competencies residing in the applicant organization for conducting the project.

4. Describe the applicant's experience and prior performance in similar programs that would be beneficial in carrying out the proposed project and outline the function and identity of all collaborating organizations in the proposed project.

5. Describe the existing or proposed linkages and formal collaborations to meet all operational and epidemiologic requirements for achieving the goals and objectives of the research agenda, including timely access to needed data and study populations and clients related to the selected area for emphasis.

6. Present letters and agreements that demonstrate commitment and support and provide tangible evidence of appropriate collaboration.

7. Describe the data to be collected, accessed, or developed to conduct the proposed project, and the methods for collecting data from specified sources. Discuss the strengths and weaknesses of each data source relative to the proposed project. Explain how the standardization and uniformity of data will be addressed to make the information useful to other organizations.

8. Present the design of the study proposal or intervention that includes: (a) Providing case definitions; (b) outlining methods of enrolling and managing cases, clients, or cohorts; (c) describing plans to ascertain cases and estimate sample size or study power; (d) describing study methods and an analytical plan; (e) describing how the confidentiality of cases identified through the project will be protected; and (f) how the research will be evaluated.

9. Present the plan for dissemination of findings and recommendations. Indicate the prospects for replicating the research in the development of interventions that will benefit other populations, including applications for national use.

10. Describe the placement of the project within the applicant organization and outline how it will function to meet the objectives of the grant. Provide an organizational chart illustrating the placement of the project and how it will interact with partner entities.

11. Present the management plan, incorporating methods and time frames for conducting the project including staff selection and appointment, intra/inter-agency agreements, data access negotiations, management oversight, and development of training or health promotion material. Provide curriculum vitae for identified key personnel.

12. Present overall goals and objectives for the entire three year project period, including detailed and specific goals and quarterly objectives with timelines, in a work plan that covers the first two budget years.

13. Present the methods, approach, and designation of responsibilities for evaluation of the management elements of the project over the duration of the grant.

14. Present what will occur to assure that all project activities and facilities will permit full access to minorities, both sexes, and persons with disabilities, and to provide opportunities for persons with disabilities to participate in research operations.

15. Prepare specific budget and cost projections with full narrative justification, for all listed budget class categories, identifying both Federal and non-Federal sources. Indicate the amount and categories of applicant cost-sharing in the total budget. Provide projections and commitments (citing sources of funding) for cost-sharing in both the second and third years of the project period.

16. *Human Subjects:* This section must describe the degree to which human subjects may be at risk and the assurance that the project will be subject to initial and continuing review by the appropriate institutional review committees.

Evaluation Criteria—Part 1 (Total 100 Points)

Under Part 1, applications for Secondary Conditions Research will be reviewed and evaluated for technical merit based on the following factors:

1. Evidence of Understanding: (15 Points)

Evaluation will be based on:

a. The applicant's description of the public health significance of secondary conditions and adherence to the purposes of this Announcement, with an emphasis on the applicant's capacity to reach the populations proposed.

b. The organizational rationale for determining the disability domain(s) for project operations, and for addressing one of the areas for emphasis outlined in the Program Requirements section for Part 1.

2. Research Resources and Organizational Capacity: (20 Points)

Evaluation will be based on:

a. The capability of the applicant to conduct the project, taking into account its institutional experience and current activities in the field proposed for this research.

b. The ability of the applicant to ensure timely access to necessary population-based data related to the selected area for emphasis.

c. The capacity of the applicant to identify and work with selected targeted activities and expeditiously gather required information about the clients or populations under investigation.

d. The applicant's capacity to provide evidence of effective collaborations and research linkages enabling the applicant to meet all protocol development and operational research requirements for the project.

3. Research Approach: (35 Points)

Evaluation will be based on:

a. The extent to which the proposed methods, sources of data, process for identifying individuals and cohorts with disabilities, and/or conducting health promotion programs will be employed and function to address the selected area for emphasis in this Announcement.

b. The overall strength of the research design including: (1) The rationale and appropriateness of the study protocol and methods; (2) the quality and scope of the data collection and data analysis plan; (3) the power of the scientific dimensions in the design, including sample size, measurements, etc; (4) the scope of the plan to assure confidentiality as applicable to the protocol; and (5) the process by which the research will be evaluated, including expected outcomes. For applicants selecting the second area for emphasis pertaining to cost-effectiveness, evaluation of the proposed methods will also be based on adherence to generally accepted techniques for conducting and reporting on cost-utility or cost-effectiveness analyses.

c. The overall information dissemination plan for presenting and publishing the findings and recommendations of the research, and the potential for generalizability and replicability of the study.

4. Management Plan and Project Goals and Objectives: (30 Points)

Evaluation will be based on:

a. The description of the management plan and approach, including the project's location within the applicant organization, and the described process by which the applicant will meet the goals and objectives of the proposed research agenda.

b. The presentation of the specified tasks and responsibilities for all positions proposed for financial assistance, and for other personnel contributing to the requirements of the project.

c. The applicability of the proposed goals and specific objectives related to the conduct of the project, including proposed timelines.

d. The process for overall evaluation of the management of the project, including the assignment of responsibility for ongoing review of specified components.

e. The extent to which the application furnishes evidence that project activities will be fully accessible to minorities, both sexes, and persons with disabilities, and will include opportunities for persons with disabilities to participate in project activities.

5. Project Budget: (Not Scored)

This criteria includes the adequacy of the project application budget in relation to program operations, collaborations, and services; the extent of cost-sharing; and the extent to which the budget is reasonable, clearly justified, accurate, and consistent with the purpose of this Announcement.

6. Human Subjects: (Not Scored)

The extent to which the applicant complies with the Department of Health and Human Services Regulations (45 CFR Part 46) regarding the protection of human subjects.

Application Contents—Part 2

1. Describe the impact of pressure sores and other proposed secondary conditions.

2. Describe the applicant organization's current activities related to the prevention of pressure sores and other secondary conditions among persons with spinal cord injuries. Define the populations included.

3. Describe the target population, the rationale for selection of that population, and whether and why the population is considered undeserved.

4. Discuss how the applicant organization is in an advantageous position to conduct the proposed project, and describe the special competencies residing in the applicant organization for conducting the project.

5. Describe the applicant's prior experience and performance in similar programs that would be beneficial in carrying out the proposed project and outline the function and identity of all collaborating organizations in the proposed project.

6. Describe the existing and proposed linkages and formal collaborations to meet all operational and epidemiologic requirements for achieving the goals and objectives of the project. Letters and agreements that demonstrate commitment and support and provide tangible evidence of collaboration for specific aspects of the proposed research must be included.

7. Present the design of the study proposal or intervention that includes: (a) Providing case definitions; (b) outlining methods of enrolling and managing cases, clients, or cohorts; (c) describing plans to ascertain cases; (d) describing study methods and an analytical plan; (e) describing how the confidentiality of cases identified through the project will be protected; and (f) how the research will be evaluated.

8. Describe the data to be collected, accessed, or developed to conduct the proposed project, and the methods for collecting data from specified sources. Discuss the strengths and weaknesses of each data source to the proposed project.

9. Present the plan for dissemination of findings and recommendations. Indicate the prospects for replicating the research in the development of interventions that will benefit other populations, including applications for national use.

10. Describe the placement of the project within the applicant organization and outline how it will function to meet the objectives of the cooperative agreement. Provide an organizational chart illustrating the placement of the project and how it will interact with partner entities.

11. Describe the management plan, incorporating methods and time frames for conducting the project in operational areas including staff selection and appointment, protocol development, intra/inter-agency agreements, data access negotiations, study population monitoring and tracking systems, data analysis, and development of training or health promotion material. Provide curriculum vitae for identified key personnel.

12. Present overall goals and objectives for the entire three year project period, including detailed and specific goals and quarterly objectives with timelines, in a work plan that covers the first two budget years.

13. Present the plan, methods, approach, and designation of responsibilities for evaluation of the management elements of the project over the duration of the project.

14. Present what will occur to assure that all project activities and facilities will permit full access to persons with disabilities, and to provide opportunities for persons with disabilities to participate in research operations.

15. Prepare specific budget and cost projections with full narrative justification, for all listed budget class categories, identifying both Federal and non-Federal sources. Indicate the amount and categories of applicant cost-sharing in the total budget. Provide projections and commitments (citing sources of funding) for cost-sharing in

both the second and third years of the project period.

16. *Human Subjects:* This section must describe the degree to which human subjects may be at risk and the assurance that the project will be subject to initial and continuing review by the appropriate institutional review committees.

Evaluation Criteria—Part 2 (Total 100 Points)

Under Part 2, applications for the Prevention of Pressure Sores and other Secondary Conditions among Persons with Spinal Cord Injury will be reviewed and evaluated for technical merit based on the following factors:

1. Evidence of Understanding: (15 Points)

Evaluation will be based on:

a. The applicant's description of the public health significance of pressure sores and other secondary conditions (as chosen by the applicant).

b. The rationale for determining the target population of persons with spinal cord injury.

2. Research Resources and Organizational Capacity: (20 Points)

Evaluation will be based on evidence of:

a. The capability of the applicant to conduct the project, taking into account prior history of conducting research and disseminating results in peer-reviewed publications and in presentations.

b. The ability of the applicant to ensure timely access to the population, including prior history of working with the target population.

c. The capacity of the applicant to identify and work with its selected targeted activities and expeditiously gather required information from the program participants and other populations related to the program activities.

d. The applicant's capacity to provide evidence of effective collaborations and research linkages (i.e., letters of commitment) enabling the applicant to meet all protocol development and operational research requirements for the project.

3. Research Approach: (35 Points)

Evaluation will be based on:

a. The extent to which the proposed methods, sources of data, process for identifying individuals and cohorts with spinal cord injuries will be employed to address the Program Requirements section for Part 2.

b. The overall strength of the research design including: (1) The rationale and appropriateness of the study protocol; (2) the quality of the data collection plan; (3) the scope of the plan to assure confidentiality as applicable to the protocol; and (4) the process by which the research will be appropriately evaluated, including expected outcomes.

c. The overall information dissemination plan for presenting and publishing the findings and recommendations of the research, and the potential for generalizability and replicability of the study.

4. Management Plan and Project Goals and Objectives: (30 Points)

Evaluation will be based on:

a. The description of the management plan and approach.

b. The presentation of the specified tasks and responsibilities for all positions proposed for financial assistance, and for other personnel contributing to the requirements of the project.

c. The applicability of the proposed goals and specific objectives related to the conduct of the project, including proposed timelines.

d. The proposed process for overall evaluation of the management of the project, including the assignment of responsibility for ongoing review of specified components.

e. The extent to which the application furnishes evidence that project activities will be fully accessible to persons with disabilities, and will include opportunities for persons with disabilities to participate in project activities.

5. Project Budget: (Not Scored)

This criteria includes the adequacy of the project budget in relation to program operations, collaborations, and services; the extent of cost-sharing; and the extent to which the budget is reasonable, clearly justified, accurate, and consistent with the purpose of this Announcement.

6. Human Subjects: (Not Scored)

The extent to which the applicant complies with the Department of Health and Human Services Regulations (45 CFR Part 46) regarding the protection of human subjects.

Reporting Requirements

Narrative progress reports will be required twice annually; and will be due 30 days after the close of each six-month period based on the starting date of the project. An original and four copies of the narrative progress report should be submitted to the CDC Grants Management Branch at dates to be specified in the Notice of Grant Award. An original and two copies of the Financial Status Report is required no later than 90 days after the end of each budget period.

Funding Priorities

Under Part 1, four areas are listed for emphasis within the Program Requirements section. To the extent that there are a sufficient number of high-ranking applications, CDC plans to make awards in all four areas of emphasis. Part 1 applications will be reviewed by an internal CDC review panel.

Under Part 2, CDC plans to fund one project to address pressure sore prevention among persons with spinal cord injury. Part 2 applications will be reviewed by a Special Emphasis Panel (SEP) with knowledge and expertise in pressure sores and/or epidemiology and public health. The SEP may consist of a physiatrist, a physical therapist, an epidemiologist, a program management official, and a person with a disability or family member of a person with a disability.

Special Instructions

Applicants must submit a separate, typed abstract or summary of their proposal consisting of no more than two double-spaced pages as a cover to their application. Applicants should include a table of contents for both the project narrative and attachments. Applicants must denote the component of this Announcement (Part 1 or Part 2) for which they are submitting a proposal. The budget narrative and full budget justification must be placed immediately after the table of contents and abstract for the main application. Applicants should follow the application contents section for the selected component of this Announcement, as those elements are arranged to be compatible with the respective evaluation criteria.

The main body of the application narrative should not exceed 50 double-spaced pages. Pages must be numbered and printed on only one side of the page. All material must be typewritten; with 10 characters per inch type (12 point) on 8–½″ by 11″ white paper with at least 1 margins, headers and footers (except for applicant-produced forms such as organizational charts, graphs and tables, etc.). Applications must be held together only by rubber bands or metal clips, and not bound together in any other way.

Attachments to the application should be held to a minimum in keeping to those items required by this Announcement. Other columns on the Standard Form 424A budget sheet should be used to define and certify other cost-sharing, with the specific sources identified and documented in the budget narrative.

CDC expects to sponsor annual project workshops for all grantees. By virtue of accepting an award, projects have agreed to use grant or cooperative agreement funds to travel to and participate in these workshops. Applicants should budget travel funds to attend a workshop in Atlanta during the first year.

Executive Order 12372

Applications are not subject to the Intergovernmental Review of Federal Programs as governed by Executive Order 12372.

Public Health System Reporting Requirements

This program is not subject to the Public Health System Reporting Requirements.

Catalog of Federal Domestic Assistance (CFDA)

The Catalog of Federal Domestic Assistance number is 93.184.

Other Requirements

Human Subjects

If the proposed project involves research on human subjects, the applicant must comply with the Department of Health and Human Services Regulations, 45 CFR Part 46, regarding the protection of human subjects. Assurance must be provided to demonstrate that the project will be subject to initial and continuing review by an appropriate institutional review committee. Applicants will be responsible for providing assurance in accordance with the appropriate guidelines and forms provided in the application kit.

In addition to other applicable committees, Indian Health Service (IHS) institutional review committees also must review the project if any component of IHS will be involved or will support the research. If any American Indian community is involved, its tribal government must also approve that portion of the project applicable to it.

Paperwork Reduction Act

Projects that involve the collection of information from 10 or more individuals, and funded by grants/cooperative agreements will be subject to review by the Office of Management and Budget (OMB) under the Paperwork Reduction Act.

Animal Subjects

If the proposed project involves research on animal subjects, the applicant must comply with the ‘‘PHS Policy on Humane Care and Use of Laboratory Animals by Awardee Institutions.’’ An applicant organization proposing to use vertebrate animals in PHS-supported activities must file an Animal Welfare Assurance with the Office of Protection from Research Risks at the National Institutes of Health.

Women and Minority Inclusion Policy

It is the policy of CDC to ensure that women and racial and ethnic groups will be included in CDC-supported research projects involving human subjects, whenever feasible and appropriate. Racial and ethnic groups are those defined in OMB Directive Number 15 and include American Indian, Alaska Native, Asian, Pacific Islander, Black, and Hispanic. Applicants shall ensure that women, racial, and ethnic minority populations are appropriately represented in applications for research involving human subjects. Where clear and compelling rationale exist that inclusion is inappropriate or not feasible, this situation must be explained as part of the application. In conducting the review of applications for scientific merit, review groups will evaluate proposed plans for inclusion of minorities and both sexes as part of the scientific assessment and assigned score. This policy does not apply to research studies when the investigator cannot control the race, ethnicity, and/or sex of subjects. Further guidance to this policy is contained in the Federal Register, Vol.60, No. 179, Friday, September 15, 1995, pages 47947–47951.

Application Submission and Deadline

A. Pre-Application Letter of Intent

Although not a prerequisite of application, a non-binding letter of intent to apply is requested from potential applicants. The letter should be submitted to the Grants Management Officer whose name is noted in section B below. The letter should be postmarked no later than 30 days prior to the submission deadline. The letter of intent should identify the Announcement Number; name the proposed project director; and in a paragraph, describe the scope of the proposed project. The letter will not influence review or funding decisions, but it will enable CDC to plan the review more efficiently and ensure that each applicant receives timely and relevant information prior to application submission.

B. Application Submission

Applicants should submit an original and four copies of the application (PHS Form 398—OMB Number 0925–0001 revised 5/95), and adhere to the ERRATA Instruction Sheet contained in the Grant Application Kit. Applications must be submitted to Mr. Ron Van Duyne, Grants Management Officer, Grants Management Branch, Procurement and Grants Office, Centers for Disease Control and Prevention (CDC), 255 East Paces Ferry Road, NE., Room 300, Mailstop E–13, Atlanta, Georgia 30305, on or before Thursday, May 15, 1997.

1. *Deadline:* Applications will be considered as meeting the deadline if they are either:

a. Received on or before the deadline date; or

b. Sent on or before the deadline date and received in time for submission to the objective review group. (Applicants must request a legibly dated U. S. Postal Service postmark or obtain a legibly dated receipt from a commercial carrier or the U. S. Postal Service. Private metered postmarks will not be acceptable as proof of timely mailing.)

2. *Late Applications:* Applications that do not meet the criteria in 1.a. or 1.b. above are considered late. Late applications will not be considered in the current competition and will be returned to the applicant.

Where To Obtain Additional Information

To receive additional written information call (404) 332–4561. You will be asked your name, address, and telephone number and will need to refer to Announcement Number 731. You will receive a complete program description, information on application procedures, and application forms. In addition, this Announcement and the bibliography attachment for Part 1 is also available through the CDC Home Page on the Internet. The address for the CDC Home Page is http://www.cdc.gov. If you have questions after reviewing the contents of all the documents, business management technical assistance may be obtained from Georgia L. Jang, Grants Management Specialist, Grants Management Branch, Procurement and Grants Office, Centers for Disease Control and Prevention (CDC), East Paces Ferry Road, NE., Room 321, Mailstop E–13, Atlanta, Georgia 30305, telephone number (404) 842–6814. (Internet address: glj2@cdc.gov).

For Part 1 applications, program assistance may be obtained from Joseph

B. Smith, Office on Disability and Health, National Center for Environmental Health, CDC, 4770 Buford Highway, Building 101, Mailstop F–29, Atlanta, Georgia 30341, telephone (770) 488–7082. (Internet address: jos4@cdc.gov). Epidemiologic and research-related technical assistance is available from Donald J. Lollar, Ed.D. at the same address, telephone (770) 488–7094. (Internet address: dcl5@cdc.gov).

For Part 2 applications, program assistance may be obtained from Douglas R. Browne, National Center for Injury Prevention and Control, CDC, 4770 Buford Highway, Building 101, Mailstop F–41, Atlanta, Georgia 30341, telephone (770) 488–4031. Internet address: drb7@cdc.gov. Epidemiologic and research-related technical assistance is available from Joe Sniezek, M.D., M.P.H. at the same address and telephone number. Internet address: jes6@cdc.gov. A packet of background information for Part 2 is available by contacting the above listed CDC staff.

Potential applicants may obtain a copy of ''Healthy People 2000'' (Full Report; Stock number 017–001–00474–0) or ''Healthy People 2000'' (Summary Report; Stock number 017–001–00473–1) through the Superintendent of Documents, Government Printing Office, Washington, DC 20402–9325, telephone (202) 512–1800.

Dated: March 7, 1997.

Joseph R. Carter,

Acting Associate Director for Management and Operations, Centers for Disease Control and Prevention (CDC).

[FR Doc. 97–6489 Filed 3–13–97; 8:45 am]

BILLING CODE 4163–18–P

Food and Drug Administration

[Docket No. 97N–0036]

Agency Information Collection Activities; Announcement of OMB Approval

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) is announcing that a collection of information regarding the Cosmetic Product Voluntary Reporting Program has been approved by the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1995. This document announces the OMB approval number.

FOR FURTHER INFORMATION CONTACT: Margaret R. Wolff, Office of Information Resources Management (HFA–80), Food and Drug Administration, 5600 Fishers Lane, rm. 16B–19, Rockville, MD 20857, 301–827–1223.

SUPPLEMENTARY INFORMATION: In the Federal Register of December 23, 1996 (61 FR 67556), the agency announced that the proposed information collection had been submitted to OMB for review and clearance. In accordance with the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520), OMB has approved the information collection and assigned OMB control number 0910–0030. The approval expires on January 31, 2000. Under 5 CFR 1320.5(b), an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection displays a valid control number.

Dated: March 7, 1997.

William K. Hubbard,

Associate Commissioner for Policy Coordination.

[FR Doc. 97–6524 Filed 3–13–97; 8:45 am]

BILLING CODE 4160–01–F

[Docket No. 96N–0497]

I. D. Russell Co. Laboratories; Withdrawal of Approval of NADA

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) is withdrawing approval of a new animal drug application (NADA) held by I. D. Russell Co. Laboratories. The NADA provides for use of 10 percent sulfaquinoxaline powder for making animal feed and 20 percent sulfaquinoxaline liquid. The sponsor requested the withdrawal of approval because the products are no longer being marketed.

EFFECTIVE DATE: March 24, 1997.

FOR FURTHER INFORMATION CONTACT: Dianne T. McRae, Center for Veterinary Medicine (HFV–102), Food and Drug Administration, 7500 Standish Pl., Rockville, MD 20855, 301–594–1623.

SUPPLEMENTARY INFORMATION: I. D. Russell Co. Laboratories, 1301 Iowa Ave., Longmont, CO 80501, is the sponsor of NADA 6–776, which provides for use of 10 percent sulfaquinoxaline powder for feed and 20 percent sulfaquinoxaline liquid. I. D. Russell Co. Laboratories requested that FDA withdraw approval of NADA 6–776 because the products are no longer being marketed.

Therefore, under authority delegated to the Commissioner of Food and Drugs (21 CFR 5.10) and redelegated to the Center for Veterinary Medicine (21 CFR 5.84), and in accordance with § 514.115 *Withdrawal of approval of applications* (21 CFR 514.115), notice is given that approval of NADA 6–776 and all supplements and amendments thereto is hereby withdrawn, effective March 24, 1997.

Dated: February 3, 1997.

Stephen F. Sundlof,

Director, Center for Veterinary Medicine.

[FR Doc. 97–6474 Filed 3–13–97; 8:45 am]

BILLING CODE 4160–01–F

[Docket Nos. 95P–0061, 95S–0117, 95S–0126, and 95S–0135]

Expiration Dates for Patents Extended by the Uruguay Round Agreements Act; Submission by Applicants of New Drug and New Animal Drug Applications; Withdrawal of Notice

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) is withdrawing a notice published in the Federal Register of July 21, 1995 (60 FR 37652), which announced the agency's position on patent information submitted by applicants of new drug applications (NDA's) and new animal drug applications (NADA's). On April 4, 1996, the U.S. Court of Appeals for the Federal Circuit issued a decision establishing the correct method for calculating patent term expiration dates for certain patents that are subject to both the Uruguay Round Agreements Act (URAA) and the patent term extension provisions of the U.S. Code. All NDA and NADA applicants should calculate patent term expiration dates in conformance with the court's decision and submit corrected patent term expiration dates to the agency.

DATES: NDA and NADA applicants that have already submitted patent term expiration dates should submit patent term expiration dates calculated in accordance with this notice by April 14, 1997.

ADDRESSES: Two copies of amended patent information pertaining to human drug products regulated under section 505 of the Federal Food, Drug, and Cosmetic Act (the act) (21 U.S.C. 355) by the Center for Drug Evaluation and Research (CDER) should be submitted to the assigned reviewing division. The submission should bear the pertinent NDA number.

Two copies of amended patent information pertaining to human drug products regulated under section 505 of the act by the Center for Biologics

Evaluation and Research (CBER) should be submitted to the Document Control Center, Center for Biologics Evaluation and Research (HFM–99), Food and Drug Administration, 1401 Rockville Pike, suite 200N, Rockville, MD 20852.

A third copy of the amended patent information pertaining to human drug products regulated under section 505 of the act by either CDER or CBER should be sent to the Division of Database Management, Drug Information Services Branch (HFD–85), Center for Drug Evaluation and Research, Food and Drug Administration, 1901 Chapman Ave., rm. 218, Rockville, MD 20852.

Two copies of amended patent information pertaining to animal drug products should be sent to the Document Control Unit, Center for Veterinary Medicine (HFV–199), Food and Drug Administration, 7500 Standish Pl., Rockville, MD 20855.

FOR FURTHER INFORMATION CONTACT: Wayne H. Mitchell, Center for Drug Evaluation and Research (HFD–7), Food and Drug Administration, 7500 Standish Pl., Rockville, MD 20855, 301–594–1049.

SUPPLEMENTARY INFORMATION: FDA is withdrawing the July 21, 1995, notice, which announced the agency's position on patent information submitted by applicants of NDA's and NADA's. In that notice, FDA stated that patent term expiration dates for certain patents that are subject to both the URAA and the patent term extension provisions of Title II of the Drug Price Competition and Patent Term Restoration Act and Title II of the Generic Animal Drug and Patent Term Restoration Act, both codified at 35 U.S.C. 156, should be calculated in accordance with the Patent and Trademark Office's determination (PTO determination) published in the Federal Register of June 7, 1995 (60 FR 30069). FDA also announced that it would not publish dates in ''Approved Drug Products with Therapeutic Equivalence Evaluations'' (the Orange Book) or the ''FDA Approved Animal Drug Products'' (the Green Book) that the NDA or NADA applicant stated were not in accordance with the PTO determination.

The PTO determination and the July 21, 1995, notice were challenged in Federal court by a number of pharmaceutical companies that hold NDA's or NADA's. On April 4, 1996, the U.S. Court of Appeals for the Federal Circuit issued a decision in *Merck & Co.* v. *Kessler*, 80 F.3d 1543 (Fed. Cir. 1996) establishing the correct method for calculating patent expiration dates for patents subject to both patent extension under the URAA and the patent term extension provisions of 35 U.S.C. 156. The Federal Circuit remanded the case to the U.S. District Court for the Eastern District of Virginia, which issued orders that, among other things, established the patent expiration dates for the patents at issue in the litigation. (*Merck & Co.* v. *Kessler*, Civ. No. 95–1005–A (E.D. Va. Sept. 5, 1996); and *Organon, Inc.* v. *Kessler*, Civ. No. 95–1380–A (E.D. Va. Sept. 13, 1996).)

In conformance with the district court order, FDA is publishing the patent expiration dates determined in the order for the patents directly at issue in the litigation in the monthly supplement to the Orange Book. FDA advises that NDA and NADA applicants should submit to FDA within 30 days, new patent expiration dates calculated in accordance with the courts' orders for any patents that have already been submitted to FDA. Patent expiration dates already submitted to the agency that were calculated by the method described in the court's order need not be resubmitted. Expiration dates for patents first submitted to FDA after the date of this notice must be calculated in accordance with the method described in *Merck & Co.* v. *Kessler*.

Two copies of amended patent information pertaining to human drug products regulated under section 505 of the act by CDER should be submitted to the assigned reviewing division. The submission should bear the pertinent NDA number.

Two copies of amended patent information pertaining to human drug products regulated under section 505 of the act by CBER should be submitted to the Document Control Center, Center for Biologics Evaluation and Research (HFM–99), Food and Drug Administration, 1401 Rockville Pike, suite 200N, Rockville, MD 20852.

To expedite the availability to the public of the updated patent information, a third copy of the amended patent information pertaining to human drug products regulated under section 505 of the act by either CDER or CBER should be sent to the Division of Database Management, Drug Information Services Branch (HFD–85), Center for Drug Evaluation and Research, Food and Drug Administration, 1901 Chapman Ave., rm. 218, Rockville, MD 20852.

Two copies of amended patent information pertaining to animal drug products should be sent to the Document Control Unit, Center for Veterinary Medicine (HFV–199), Food and Drug Administration, 7500 Standish Pl., Rockville, MD 20855.

Dated: March 7, 1997.

William K. Hubbard,

Associate Commissioner for Policy Coordination.

[FR Doc. 97–6413 Filed 3–13–97; 8:45 am]

BILLING CODE 4160–01–F

[Docket No. 97M–0051]

Eurexpan Labo; Premarket Approval of ContaClair® Multi-Purpose Solution

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) is announcing its approval of the application submitted by the law firm of Akin, Gump, Strauss, Hauer and Field, as the United States Representative on behalf of Eurexpan Labo, 41120 Cellettes, France, for premarket approval, under the Federal Food, Drug, and Cosmetic Act (the act), of ContaClair® Multi-Purpose Solution. FDA's Center for Devices and Radiological Health (CDRH) notified the applicant, by letter of June 20, 1996, of the approval of the application.

DATES: Petitions for administrative review by April 14, 1997.

ADDRESSES: Written requests for copies of the summary of safety and effectiveness data and petitions for administrative review to the Dockets Management Branch (HFA–305), Food and Drug Administration, 12420 Parklawn Dr., rm. 1–23, Rockville, MD 20857.

FOR FURTHER INFORMATION CONTACT: James F. Saviola, Center for Devices and Radiological Health (HFZ–460), Food and Drug Administration, 9200 Corporate Blvd., Rockville, MD 20850, 301–594–1744.

SUPPLEMENTARY INFORMATION: On December 19, 1991, the law firm of Akin, Gump, Strauss, Hauer and Field, as the United States Representative on behalf of Eurexpan Labo, 41120 Cellettes, France, submitted to CDRH an application for premarket approval of ContaClair® Multi-Purpose Solution. The device is a cleaning, rinsing, disinfecting, and storing solution and is indicated for cleaning, rinsing, disinfecting, and storing daily and extended wear clear and tinted soft (hydrophilic) contact lenses.

In accordance with the provisions of section 515(c)(2) of the act (21 U.S.C. 360e(c)(2)) as amended by the Safe Medical Devices Act of 1990, this premarket approval application (PMA) was not referred to the Ophthalmic Devices Panel of the Medical Devices Advisory Committee, an FDA advisory committee, for review and recommendation because the information in the PMA substantially duplicates information previously reviewed by this panel.

On June 20, 1996, CDRH approved the application by a letter to the applicant from the Director of the Office of Device Evaluation, CDRH.

A summary of the safety and effectiveness data on which CDRH based its approval is on file in the Dockets Management Branch (address above) and is available from that office upon written request. Requests should be identified with the name of the device and the docket number found in brackets in the heading of this document.

Opportunity for Administrative Review

Section 515(d)(3) of the act authorizes any interested person to petition, under section 515(g) of the act, for administrative review of CDRH's decision to approve this application. A petitioner may request either a formal hearing under 21 CFR part 12 of FDA's administrative practices and procedures regulations or a review of the application and CDRH's action by an independent advisory committee of experts. A petition is to be in the form of a petition for reconsideration under 21 CFR 10.33(b). A petitioner shall identify the form of review requested (hearing or independent advisory committee) and shall submit with the petition supporting data and information showing that there is a genuine and substantial issue of material fact for resolution through administrative review. After reviewing the petition, FDA will decide whether to grant or deny the petition and will publish a notice of its decision in the Federal Register. If FDA grants the petition, the notice will state the issue to be reviewed, the form of the review to be used, the persons who may participate in the review, the time and place where the review will occur, and other details.

Petitioners may, at any time on or before April 14, 1997, file with the Dockets Management Branch (address above) two copies of each petition and supporting data and information, identified with the name of the device and the docket number found in brackets in the heading of this document. Received petitions may be seen in the office above between 9 a.m. and 4 p.m., Monday through Friday.

This notice is issued under the Federal Food, Drug, and Cosmetic Act (secs. 515(d), 520(h) (21 U.S.C. 360e(d), 360j(h))) and under authority delegated to the Commissioner of Food and Drugs (21 CFR 5.10) and redelegated to the Director, Center for Devices and Radiological Health (21 CFR 5.53).

Dated: January 16, 1997.

Joseph A. Levitt,

Deputy Director for Regulations Policy, Center for Devices and Radiological Health.

[FR Doc. 97–6409 Filed 3–13–97; 8:45 am]

BILLING CODE 4160–01–F

[Docket No. 97N–0083]

Abbreviated New Drug Applications; Positron Emission Tomography Radiopharmaceuticals; Notice of a Public Workshop

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) is announcing a public workshop to provide information to the positron emission tomography (PET) radiopharmaceutical industry on submitting abbreviated new drug applications (ANDA's) and other regulatory issues affecting PET radiopharmaceutical drug products. The workshop will provide guidance on topics such as ANDA regulatory requirements, registration and listing requirements, chemistry and manufacturing controls, sterility assurance, bioequivalence requirements, and labeling. An agenda and materials to be discussed at the workshop will be available before the workshop.

DATES: The workshop will be held on Monday, April 28, 1997, from 8 a.m. to 5 p.m. Because space is limited, interested persons are encouraged to register as soon as possible. Preregistration will be accepted through April 18, 1997. There is no registration fee for the workshop. The administrative docket will remain open until June 27, 1997, to receive written comments, data, information, or views on the workshop and materials distributed at the workshop.

ADDRESSES: The workshop will be held at the Parklawn Bldg., 5600 Fishers Lane, conference rm. D, Rockville, MD 20857. Persons interested in attending should pre-register by faxing their name, title, organization name if any, address, telephone and fax numbers to the contact person. Registrants' fax numbers should be provided, so that registration can be confirmed by return fax.

Before the workshop, the agenda and materials to be discussed at the workshop will be available via the Internet using the World Wide Web (WWW). To connect to the Center for Drug Evaluation and Research (CDER) Home Page, type http://www.fda.gov/cder and go to the ''What's Happening'' section. A transcript of the workshop will be available from the Freedom of Information Office (HFI–35), Food and Drug Administration, 5600 Fishers Lane, Rockville, MD 20857, approximately 15 business days after the workshop at a cost of 10 cents per page.

Written comments on the workshop or materials discussed at the workshop can be submitted until June 27, 1997, to the Dockets Management Branch (HFA–305), 12420 Parklawn Dr., rm. 1–23, Rockville, MD 20857. Two copies of comments are to be submitted, except that individuals may submit one copy. Comments are to be identified with the docket number found in brackets in the heading of this notice. Received comments may be viewed at the Dockets Management Branch between 9 a.m. and 4 p.m., Monday through Friday.

FOR FURTHER INFORMATION CONTACT: Susan C. Lange, Food and Drug Administration, Center for Drug Evaluation and Research (HFD–160), 5600 Fishers Lane, Rockville, MD 20857, 301–443–0260, FAX 301–594–0746.

SUPPLEMENTARY INFORMATION:

I. Background

PET is a diagnostic imaging modality consisting of onsite production of radionuclides that are usually intravenously injected into patients for diagnostic purposes. The potential usefulness of a PET radiopharmaceutical is based upon the product's interaction with a biochemical process in the body.

Over the last 20 years, there has been increasingly widespread commercial use of a growing number of PET radiopharmaceuticals. Having considered the available information, including that presented to the agency at a March 1993 hearing and in written materials, in the Federal Register of February 27, 1995 (60 FR 10593), FDA provided additional notice and guidance to the industry stating how the agency would apply its regulatory authority to PET drug products.

Since the approval of one new drug application for F–18 FDG, PET drug product manufacturers have sought information on the submission of ANDA's. Details of the ANDA submission process will be discussed at the workshop. Other topics to be addressed include registration and listing requirements, chemistry and manufacturing controls, sterility assurance, bioequivalence requirements, labeling, and compliance with current good manufacturing practice regulations and other regulatory requirements. Materials providing guidance on ANDA submissions and related topics will also be discussed at the workshop.

Dated: March 10, 1997.

William K. Hubbard,

Associate Commissioner for Policy Coordination.

[FR Doc. 97–6410 Filed 3–13–97; 8:45 am]

BILLING CODE 4160–01–F

Health Resources and Services Administration

Notice Regarding Section 602 of the Veterans Health Care Act of 1992 Rebate Mechanism

AGENCY: Health Resources and Services Administration, HHS.

ACTION: Notice.

SUMMARY: Section 602 of Public Law 102–585, the ''Veterans Health Care Act of 1992,'' enacted section 340B of the Public Health Service (PHS) Act, ''Limitation on Prices of Drugs Purchased by Covered Entities.'' Section 340B provides that a manufacturer who sells covered outpatient drugs to eligible entities must sign a pharmaceutical pricing agreement with the Secretary of HHS in which the manufacturer agrees to charge a price for covered outpatient drugs that will not exceed that amount determined under a statutory formula.

The purpose of this notice is to request comments on the proposal of a rebate process for State AIDS Drug Assistance Programs (ADAPs) receiving funds under Title XXVI of the PHS Act.

DATES: The public is invited to submit comments on the proposed rebate process by April 14, 1997. After consideration of comments submitted, the Secretary will issue the final guideline.

ADDRESS: Comments should be submitted to: Annette Byrne, R. Ph., M.S., Director, Office of Drug Pricing Program, Bureau of Primary Health Care, Health Resources and Services Administration, 4350 East-West Highway, Bethesda, MD 20814, Phone (301) 594–4353; FAX (301) 594–4982.

FOR FURTHER INFORMATION CONTACT: Robert Staley, R. Ph., Senior Program Manager, Office of Drug Pricing Program, Bureau of Primary Health Care, Health Resources and Services Administration, 4350 East-West Highway, Bethesda, MD 20814, Phone (301) 594–4353; Fax (301) 594–4982.

SUPPLEMENTARY INFORMATION: Section 340B requires manufacturers, as a condition for the receipt of Medicaid matching funds with respect to their covered outpatient drugs, to charge participating entities no more than a ceiling price for such drugs. This price is determined by reducing the average manufacturer price of the drug by a rebate percentage. Entities eligible to access section 340B pricing (covered entities) include certain PHS grantees (e.g., federally-qualified health centers, certain family planning projects, AIDS assistance programs, black lung clinics, hemophilia treatment centers, Native Hawaiian health centers, and centers that treat sexually-transmitted disease and/or tuberculosis) and certain disproportionate share hospitals.

Section 340B has no explicit language as to whether the required reduction in price should be obtained by an initial reduction in the purchase price (i.e., a discount system) or received as a required reduction in cost rebated after purchase, dispensing, and payment are completed (i.e., a rebate system). Section 340B(a)(1) of the PHS Act provides that the amount to be paid to the manufacturers for covered drugs takes ''into account any rebate or discount, as provided by the Secretary * * * '' Further, section 340B does not specify whether entities should receive the section 340B pricing ''through a point of purchase discount, through a manufacturer rebate, or through some other mechanism. A mechanism that is appropriate to one type of 'covered entity,' such as community health centers, may not be appropriate to another type, such as State AIDS drug assistance programs * * * [T]he Secretary of HHS * * * will use the mechanism that is the most effective and most efficient * * * ''. H.R. Rep. No 102–384, 102d Cong., 2d Sess., pt. 2, at 16 (1992).

Initially, HRSA guidance for the section 340B program described only a discount process. Covered entities generally preferred a discount system, because they could negotiate lower prices and needed less initial outlay of drug purchasing money.

Although the discount system is functioning successfully for most covered entities, most ADAPs have drug purchasing systems that have prevented their participation in the section 340B discount program. The use of a rebate mechanism (in addition to the discount mechanism) should allow these groups to access section 340B pricing.

The HRSA recognizes rebates obtained by the State ADAPs as a method of accessing the section 340B discount price. The rebate for covered outpatient drugs should be equal to or greater than the section 340B discount at the time of purchase price. State ADAPs wishing technical assistance in developing a rebate program should contact HRSA's Office of Drug Pricing at (301) 594–4353 or (800) 628–6297.

The HRSA is sensitive to concerns about diversion of covered drugs to individuals who are not patients of the covered entities. Guidelines have been issued to minimize this potential, and manufacturers have available to them specified remedies if they believe diversion has occurred. The HRSA believes that these guidelines and remedies will apply fully to drugs purchased under a rebate procedure and that instituting rebates will not increase the potential for diversion.

Dated: March 10, 1997.

Ciro V. Sumaya,

Administrator.

[FR Doc. 97–6414 Filed 3–13–97; 8:45 am]

BILLING CODE 4160–15–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR–4200–N–34]

Notice of Proposed Information Collection for Public Comment

AGENCY: Office of the Assistant Secretary for Housing, HUD.

ACTION: Notice.

SUMMARY: The proposed information collection requirement described below will be submitted to the Office of Management and Budget (OMB) for review, as required by the Paperwork Reduction Act. The Department is soliciting public comments on the subject proposal.

DATES: Comments due: May 13, 1997.

ADDRESSES: Interested persons are invited to submit comments regarding this proposal. Comments should refer to the proposal by name and/or OMB Control Number and should be sent to: Oliver Walker, Housing, Department of Housing & Urban Development, 451–7th Street, SW, Room 9116, Washington, DC 20410.

FOR FURTHER INFORMATION CONTACT: Daniel Kahn, telephone number (202) 708–2121 (this is not a toll-free number) for copies of the proposed forms and other available documents.

SUPPLEMENTARY INFORMATION: The Department will submit the proposed information collection to OMB for review, as required by the Paperwork Reduction Act of 1995 (44 U.S.C. Chapter 35, as amended).

The Notice is soliciting comments from members of the public and affecting agencies concerning the proposed collection of information to: (1) 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; (2) Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information; (3) Enhance the quality, utility, and clarity of the information to be collected; and (4) Minimize the burden of the collection of information on those who are to respond; including through the use of appropriate automated collection techniques or other forms of information technology, e.g., permitting electronic submission of responses.

This Notice also lists the following information:

Title of Proposal: Request for Insurance Endorsement Under the Direct Endorsement Program.

OMB Control Number: 2502–0365.

Description of the need for the information and proposed use: The Direct Endorsement Program permits mortgage lenders to underwrite applications for mortgage insurance and close mortgage loans without prior HUD review. Lenders then submit the closing package to HUD with request for insurance endorsement. The request is keyed into HUD's computer system to speed the process of issuing a computer-generated mortgage insurance certificate.

Agency forms, if applicable: HUD–54111.

Members of affected public: lenders performing underwriting functions.

Status of the proposed information collection: extension without change.

Authority: Section 236 of the Paperwork Reduction Act of 1995, 44 U.S.C. Chapter 35, as amended.

Dated: March 4, 1997.

Nicolas P. Retsinas,

Assistant Secretary for Housing-Federal Housing Commissioner.

[FR Doc. 97–6460 Filed 3–13–97; 8:45 am]

BILLING CODE 4210–27–M

[Docket No. FR–4200–N–40]

Notice of Proposed Information Collection for Public Comment

AGENCY: Office of the Assistant Secretary for Housing—Federal Housing Commissioner, HUD.

ACTION: Notice.

SUMMARY: The proposed information collection requirement described below will be submitted to the Office of Management and Budget (OMB) for review, as required by the Paperwork Reduction Act. The Department is soliciting public comments on the subject proposal.

DATES: Comments due: May 13, 1997.

ADDRESSES: Interested persons are invited to submit comments regarding this proposal. Comments should refer to the proposal by name and/or OMB Control Number and should be sent to: Oliver Walker, Housing, Department of Housing & Urban Development, 451–7th Street, SW., Room 9116, Washington, DC 20410.

FOR FURTHER INFORMATION CONTACT: John Coonts, Director, Office of Insured Single Family Housing, Telephone number (202) 708–3046 (this is not a toll-free number) for copies of the proposed forms and other available documents.

SUPPLEMENTARY INFORMATION: The Department will submit the proposed information collection to OMB for review, as required by the Paperwork Reduction Act of 1995 (44 U.S.C. Chapter 35, as amended).

The notice is soliciting comments from members of the public and affecting agencies concerning the proposed collection of information to: (1) 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; (2) Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information; (3) Enhance the quality, utility, and clarity of the information to be collected; and (4) Minimize the burden of the collection of information on those who are to respond; including through the use of appropriate automated collection techniques or other forms of information technology, e.g., permitting electronic submission of responses.

This Notice also lists the following information:

Title of Proposal: Insurance of Adjustable Rate Mortgages.

OMB Control Number: 2502–0322

Description of the need for thee information and proposed use: P.L. 98–181 requires lenders to furnish to the borrower a disclosure statement indicating that the interest rate may change. This disclosure also must identify the index used, indicate the frequency of the adjustments and provide any potential payment schedule showing increases over the first five years. An annual disclosure of interest rate adjustment is also required.

Agency form number: N/A.

Members of affected public: Business or other for-profit and individuals or households.

An estimation of the total numbers of hours needed to prepare the information collection is 1400, the number of respondents is 20,000, frequency of response is annually or on occasion, and the hours of response is 0.07 per response.

Status of the proposed information collection: Extension of a currently approved collection.

Authority: Section 3506 of the Paperwork Reduction Act of 1995, 44 U.S.C. Chapter 35, as amended.

Dated: March 7, 1997.

Nicolas P. Retsinas,

Assistant Secretary for Housing-Federal Housing Commissioner.

[FR Doc. 97–6461 Filed 3–13–97; 8:45 am]

BILLING CODE 4210–27–M

[Docket No. FR–4124–N–29]

Federal Property Suitable as Facilities To Assist the Homeless

AGENCY: Office of the Assistant Secretary for Community Planning and Development, HUD.

ACTION: Notice.

SUMMARY: This Notice identifies underutilized, excess, and surplus Federal property reviewed by HUD for suitability for possible use to assist the homeless.

FOR FURTHER INFORMATION CONTACT: Mark Johnston, room 7256, Department of Housing and Urban Development, 451 Seventy Street SW, Washington, DC 20410; telephone (202) 708–1226; TDD number for the hearing- and speech-impaired (202) 708–2565 (these telephone numbers are not toll-free), or call the toll-free Title V information line at 1–800–927–7588.

SUPPLEMENTARY INFORMATION: In accordance with 24 CFR part 581 and section 501 of the Stewart B. McKinney Homeless Assistance Act (42 U.S.C. 11411), as amended, HUD is publishing this Notice to identify Federal buildings and other real property that HUD has reviewed for suitability for use to assist the homeless. The properties were reviewed using information provided to HUD by Federal landholding agencies regarding unutilized and underutilized buildings and real property controlled by such agencies or by GSA regarding its inventory of excess or surplus Federal property. This Notice is also published in order to comply with the December 12, 1988 Court Order in *National Coalition for the Homeless* v.

Veterans Administration, No. 88–2503–OG (D.D.C.).

Properties reviewed are listed in this Notice according to the following categories: Suitable/available, suitable/unavailable, suitable/to be excess, and unsuitable. The properties listed in the three suitable categories have been reviewed by the landholding agencies, and each agency has transmitted to HUD: (1) Its intention to make the property available for use to assist the homeless, (2) its intention to declare the property excess to the agency's needs, or (3) a statement of the reasons that the property cannot be declared excess or made available for use as facilities to assist the homeless.

Properties listed as suitable/available will be available exclusively for homeless use for a period of 60 days from the date of this Notice. Homeless assistance providers interested in any such property should send a written expression of interest to HHS, addressed to Brian Rooney, Division of Property Management, Program Support Center, HHS, room 5B–41, 5600 Fishers Lane, Rockville, MD 20857; (301) 443–2265. (This is not a toll-free number.) HHS will mail to the interested provider an application packet, which will include instructions for completing the application. In order to maximize the opportunity to utilize a suitable property, providers should submit their written expressions of interest as soon as possible. For complete details concerning the processing of applications, the reader is encouraged to refer to the interim rule governing this program, 24 CFR part 581.

For properties listed as suitable/to be excess, that property may, if subsequently accepted as excess by GSA, be made available for use by the homeless in accordance with applicable law, subject to screening for other Federal use. At the appropriate time, HUD will publish the property in a Notice showing it as either suitable/available or suitable/unavailable.

For properties listed as suitable/unavailable, the landholding agency has decided that the property cannot be declared excess or made available for use to assist the homeless, and the property will not be available.

Properties listed as unsuitable will not be made available for any other purpose for 20 days from the date of this Notice. Homeless assistance providers interested in a review by HUD of the determination of unsuitability should call the toll free information line at 1–800–927–7588 for detailed instructions or write a letter to Mark Johnston at the address listed at the beginning of this Notice. Included in the request for review should be the property address (including zip code), the date of publication in the Federal Register, the landholding agency, and the property number.

For more information regarding particular properties identified in this Notice (*i.e.*, acreage, floor plan, existing sanitary facilities, exact street address), providers should contact the appropriate landholding agencies at the following addresses: *Air Force:* Ms. Barbara Jenkins, Air Force Real Estate Agency, (Area-MI), Bolling Air Force Base, 112 Luke Avenue, Suite 104, Building 5683, Washington, DC 20332–8020; (202) 767–4184; *GSA:* Mr. Brian K. Polly, Assistant Commissioner, General Services Administration, Office of Property Disposal, 18th and F Streets, NW, Washington, DC 20405; (202) 501–2059; *Navy:* Mr. Charles C. Cocks, Department of the Navy, Director, Real Estate Policy Division, Naval Facilities Engineering Command, Code 241A, 200 Stovall Street, Alexandria, VA 22332–2300; (703) 325–7342; *VA:* Mr. George L. Szwarcman, Director, Land Management Service, Department of Veterans Affairs, 811 Vermont Avenue, NW, Room 414, Lafayette Bldg., Washington, DC 20420; (202) 565–5941; *Interior:* Ms. Lola D. Knight, Property Management Specialist, Department of the Interior, 1849 C Street, NW, Mail Stop 5512–MIB, Washington, DC 20240; (202) 208–4080; (These are not toll-free numbers).

Dated: March 6, 1997.

Jacquie M. Lawing,

Deputy Assistant Secretary for Economic Development.

Title V, Federal Surplus Property Program Federal Register Report for 03/14/97

Suitable/Available Properties

Buildings (by State)

California

Bldg. 20—VA Medical Center
Wilshire & Sawtelle Blvds.
Los Angeles Co: Los Angeles CA 90073–
Landholding Agency: VA
Property Number: 979210003
Status: Unutilized
Comment: 8758 gross sq. ft., one story wooden, requires complete restoration meeting standards of national preservation laws and guidelines.

Bldg. 13, VA Medical Center
Wilshire and Sawtelle Blvds.
Los Angeles Co: Los Angeles CA 90073–
Landholding Agency: VA
Property Number: 979220001
Status: Underutilized
Comment: portion of 66,165 sq. ft. bldg., needs major rehab, no util., pres. of asbestos, in historic district, potential to be hazardous due to storage of radioactive material nearby.

Bldg. 156, VAMC
Wilshire & Sawtelle Blvds.
Los Angeles Co: Los Angeles CA 90073–
Landholding Agency: VA
Property Number: 979230015
Status: Underutilized
Comment: portion of 39,454 sq. ft. bldg., presence of asbestos, needs rehab, seismic reinforcement deficiencies, in his. district, potentially hazardous due to nearby radioactive material.

Connecticut

Pier 7
Naval Undersea Warfare Center
New London Co: New London CT 06320–5594
Landholding Agency: Navy
Property Number: 779710063
Status: Excess
Comment: 700′ long by 30′ wide, rectangular shaped reinforced concrete pier.

Hawaii

Bldg. S87, Radio Trans. Fac.
Lualualei, Naval Station, Eastern Pacific
Wahiawa Co: Honolulu HI 96786–3050
Landholding Agency: Navy
Property Number: 779240011
Status: Unutilized
Comment: 7566 sq. ft., 1-story, needs rehab, most recent use—storage, off-site use only.

Bldg. 466, Radio Trans. Fac.
Lualualei, Naval Station, Eastern Pacific
Wahiawa Co: Honolulu HI 96786–3050
Landholding Agency: Navy
Property Number: 779240012
Status: Unutilized
Comment: 100 sq. ft., 1-story, needs rehab, most recent use—gas station, off-site use only.

Bldg. T33 Radio Trans Facility
Naval Computer & Telecommunications Area
Wahiawa Co: Honolulu HI 96786–3050
Landholding Agency: Navy
Property Number: 779310003
Status: Unutilized
Comment: 1536 sq. ft., 1 story, access restrictions, needs rehab, most recent use—storage, off-site use only.

Bldg. 64, Radio Trans Facility
Naval Computer & Telecommunications Area
Wahiawa Co: Honolulu HI 96786–3050
Landholding Agency: Navy
Property Number: 779310004
Status: Unutilized
Comment: 3612 sq. ft., 1 story, access restrictions, needs rehab, most recent use—storage, off-site use only.

Bldg. 594
Naval Station, Pearl Harbor
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779620011
Status: Unutilized
Comment: 1300 sq. ft., most recent use—parking garage, off-site use only.

Bldgs. S233–S234, S241–S244
Naval Station, Pearl Harbor
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779620012
Status: Unutilized
Comment: 90 sq. ft. each, need repairs, most recent use—storage, off-site use only.

Bldgs. S229–S232
Naval Station, Pearl Harbor

Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779620013
Status: Unutilized
Comment: 180 sq. ft. each, need repairs, most recent use—storage, off-site use only.

Bldg. 4, Naval Station
Pearl Harbor, Bishop Point (Hickam AFB)
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779620043
Status: Unutilized
Comment: 576 sq. ft., needs rehab, most recent use—storage, off-site use only.

Bldg. 20, Naval Station
Pearl Harbor, Bishop Point (Hickam AFB)
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779620044
Status: Unutilized
Comment: 252 sq. ft., needs rehab, most recent use—storage, off-site use only.

Bldg. 442, Naval Station
Ford Island
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779630088
Status: Excess
Comment: 192 sq. ft., most recent use—storage, off-site use only.

Bldg. S180
Naval Station, Ford Island
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779640039
Status: Unutilized
Comment: 3412 sq. ft., 2-story, most recent use—bomb shelter, off-site use only, relocation may not be feasible.

Bldg. S181
Naval Station, Ford Island
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779640040
Status: Unutilized
Comment: 4258 sq. ft., 1-story, most recent use—bomb shelter, off-site use only, relocation may not be feasible.

Bldg. 219
Naval Station, Ford Island
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779640041
Status: Unutilized
Comment: 620 sq. ft., most recent use—damage control, off-site use only, relocation may not be feasible.

Bldg. 220
Naval Station, Ford Island
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779640042
Status: Unutilized
Comment: 620 sq. ft., most recent use—damage control, off-site use only, relocation may not be feasible.

Bldg. 222
Naval Station, Ford Island
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779640043
Status: Unutilized
Comment: 620 sq. ft., most recent use—damage control, off-site use only, relocation may not be feasible.

Indiana

Bldg. 140, VAMC
East 38th Street
Marion Co: Grant IN 46952–
Landholding Agency: VA
Property Number: 979230007
Status: Underutilized
Comment: 60 sq. ft., concrete block bldg., most recent use—trash house, access restrictions.

North Carolina

Bldg. 127, Camp Lejeune
Greater Sandy Run Training Area
Camp Lejeune Co: Onslow NC 28542–
Landholding Agency: Navy
Property Number: 779620027
Status: Unutilized
Comment: 14276 sq. ft., 1-story, most recent use—garage, off-site use only

Bldg. 128, Camp Lejeune
Greater Sandy Run Training Area
Camp Lejeune Co: Onslow NC 28542–
Landholding Agency: Navy
Property Number: 779620028
Status: Unutilized
Comment: 2008 sq. ft., 2-story, most recent use—residence, may have State historical significance, off-site use only

Bldg. 146, Camp Lejeune
Greater Sandy Run Training Area
Camp Lejeune Co: Onslow NC 28542–
Landholding Agency: Navy
Property Number: 779620029
Status: Unutilized
Comment: 1900 sq., ft., concrete block, most recent use—gas station, off-site use only

Pennsylvania

Bldg. 25—VA Medical Center
Delafield Road
Pittsburgh Co: Allegheny PA 15215–
Landholding Agency: VA
Property Number: 979210001
Status: Unutilized
Comment: 133 sq. ft., one story brick guard house, needs rehab

Tennessee

Bldg. 01–204
Stones River National Battlefield
Nickens Lane
Murfreesboro Co: Rutherford TN 37129–
Landholding Agency: Interior
Property Number: 619630004
Status: Excess
Comment: 1469 sq. ft., most recent use—residential, off-site use only

Virginia

NPS Tract 422–25
Former White property
County Rd. 602 on Moore Run near 4-H Camp
Front Royal Co: Warren VA 22630–
Landholding Agency: Interior
Property Number: 619440002
Status: Excess
Comment: 864 sq. ft., 2-story frame residence, w/Natl. Appalachian Trails System Act, off-site use only

Quarters 250
Williamsburg Co: James City VA 23185–
Landholding Agency: Interior
Property Number: 619630003
Status: Excess
Comment: 1125 sq. ft., moisture problem, most recent use—residence, off-site use only

Young Property
Rt. 2, Box 547
Galax Co: Grayson VA 24333–
Landholding Agency: Interior
Property Number: 619640007
Status: Unutilized
Comment: 1113 sq. ft., residence, guest cottage, shop building, storage shed, off-site use only

Walker Property
Rt. 2, Box 553
Galax Co: Grayson VA 24333–
Landholding Agency: Interior
Property Number: 619640008
Status: Unutilized
Comment: 1200 sq. ft. residence, feed shed, workshop, haybarn, storage shed, spring house, off-site use only

Nichols Property
Rt. 2, Box 554
Galax Co: Grayson VA 24333–
Landholding Agency: Interior
Property Number: 619640009
Status: Unutilized
Comment: 1520 sq. ft. residence, off-site use only

Golding Property
Rt. 2, Box 555
Galax Co: Grayson VA 24333–
Landholding Agency: Interior
Property Number: 619640010
Status: Unutilized
Comment: 2224 sq. ft. residence, needs repair, barn, rental cottage, shed, off-site use only

Bldg. 1470
509 King Street
Portsmouth VA 23704–
Landholding Agency: Navy
Property Number: 779640044
Status: Unutilized
Comment: 21445 sq. ft., 3-story

Bldg. U48
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710011
Status: Excess
Comment: 19346 sq. ft., 2-story, off-site use only

Bldg. V17
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710012
Status: Excess
Comment: 9720 sq. ft., most recent use—shop space, off-site use only

Bldg. V14
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710013
Status: Excess
Comment: 2800 sq. ft., presence of lead paint, most recent use—storage, off-site use only

Bldg. V15
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710014

Status: Excess
Comment: 17179 sq. ft., presence of asbestos/lead paint, most recent use—shipboard repair, off-site use only

Bldg. V16
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710015
Status: Excess
Comment: 2800 sq. ft., presence of lead paint, most recent use—part store, off-site use only

Bldg. V31
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710016
Status: Excess
Comment: 23430 sq. ft., presence of lead paint/asbestos, off-site use only

Bldg. V38
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710017
Status: Excess
Comment: 16096 sq. ft., presence of asbestos/lead paint, off-site use only

Bldg. V41
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710018
Status: Excess
Comment: 12115 sq. ft., presence of asbestos/lead paint, off-site use only

Bldg. V114
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710019
Status: Excess
Comment: 3214 sq. ft., presence of asbestos/lead paint, most recent use—storage, off-site use only

Bldg. V135
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710020
Status: Excess
Comment: 20016 sq. ft., presence of asbestos/lead paint, most recent use—storage, off-site use only

Bldg. V135A
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710021
Status: Excess
Comment: 144 sq. ft., presence of lead paint, most recent use—storage, off-site use only

Bldg. V135B
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710022
Status: Excess
Comment: 2889 sq. ft., presence of lead paint, most recent use—storage, off-site use only

Bldg. V135C
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710023
Status: Excess
Comment: 645 sq. ft., presence of lead paint, most recent use—storage off-site use only

Bldg. V135D
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710024
Status: Excess
Comment: 567 sq. ft., presence of lead paint, most recent use—storage, off-site use only

Bldg. V145
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710025
Status: Excess
Comment: 1525 sq. ft., presence of lead paint, off-site use only

Bldg. LP22
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710026
Status: Excess
Comment: 46844 gross sq. ft., needs repair, presence of asbestos/lead paint, off-site use only

Bldg. LP196
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710027
Status: Excess
Comment: 297 gross sq. ft., off-site use only

Bldg. R49
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710028
Status: Excess
Comment: 12000 gross sq. ft., needs repair, presence of asbestos/lead paint, off-site use only

Bldg. R56
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710029
Status: Excess
Comment: 4000 gross sq. ft., needs repair, presence of asbestos/lead paint, off-site use only

Bldg. R60
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710030
Status: Excess
Comment: 3970 gross sq. ft., needs repair, presence of asbestos/lead paint, off-site use only

Bldg. V27
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710031
Status: Excess
Comment: 12852 gross sq. ft., needs repair, presence of asbestos/lead paint, off-site use only

Bldg. V42
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710032
Status: Excess
Comment: 13026 gross sq. ft., needs repair, presence of asbestos/lead paint, off-site use only

Bldg. V44
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710033
Status: Excess
Comment: 736 gross sq. ft., needs repair, presence of asbestos/lead paint, off-site use only

Bldg. V48
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710034
Status: Excess
Comment: 2408 gross sq. ft., presence of asbestos/lead paint, off-site use only

Bldg. LP176
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710035
Status: Excess
Comment: 25611 gross sq. ft., off-site use only

Bldg. U47
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710036
Status: Excess
Comment: 1000 gross sq. ft., off-site use only

Bldg. V43
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710037
Status: Excess
Comment: 8754 gross sq. ft., presence of asbestos, off-site use only

Bldg. V45
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710038
Status: Excess
Comment: 1343 gross sq. ft., battery contamination, presence of asbestos, off-site use only

Bldg. LF38
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710039
Status: Excess
Comment: 5292 gross sq. ft., needs repair, off-site use only

Bldg. V30AQ
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710040
Status: Excess
Comment: 340 gross sq. ft., needs repair, most recent use—storage, off-site use only

Bldg. V102

Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710041
Status: Excess
Comment: 4000 gross sq. ft., off-site use only

Bldg. V109
Naval Base Norfolk
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779710042
Status: Excess
Comment: 464 gross sq. ft., off-site use only

Bldg. 1131
Naval Amphibious Base
Norfolk VA
Landholding Agency: Navy
Property Number: 779710043
Status: Excess
Comment: 31000 sq. ft., most recent use—storage, off-site use only

Bldg. 3336
Naval Amphibious Base
Norfolk VA
Landholding Agency: Navy
Property Number: 779710044
Status: Excess
Comment: 18719 sq. ft., 2-story, most recent use—storage, off-site use only

Bldg. 3373
Naval Amphibious Base
Norfolk VA
Landholding Agency: Navy
Property Number: 779710045
Status: Excess
Comment: 1882 sq. ft., most recent use—office, off-site use only

Bldg. 34
Naval Base Norfolk, St. Julien's Creek Annex Co: Chesapeake VA
Landholding Agency: Navy
Property Number: 779710046
Status: Excess
Comment: 1260 sq. ft., off-site use only

Bldg. 91
Naval Base Norfolk, St. Julien's Creek Annex Co: Chesapeake VA
Landholding Agency: Navy
Property Number: 779710047
Status: Excess
Comment: 780 sq. ft., off-site use only

Bldg. 141
Naval Base Norfolk, St. Julien's Creek Annex Co: Chesapeake VA
Landholding Agency: Navy
Property Number: 779710048
Status: Excess
Comment: 414 sq. ft., off-site use only

Bldg. 213
Naval Base Norfolk, St. Julien's Creek Annex Co: Chesapeake VA
Landholding Agency: Navy
Property Number: 779710049
Status: Excess
Comment: 1328 sq. ft., off-site use only

Bldg. 224
Naval Base Norfolk, St. Julien's Creek Annex Co: Chesapeake VA
Landholding Agency: Navy
Property Number: 779710050
Status: Excess
Comment: 512 sq. ft., off-site use only

Bldgs. 237–238
Naval Base Norfolk, St. Julien's Creek Annex Co: Chesapeake VA
Landholding Agency: Navy
Property Number: 779710051
Status: Excess
Comment: 63 sq. ft., each, off-site use only

Bldgs. 241–243
Naval Base Norfolk, St. Julien's Creek Annex Co: Chesapeake VA
Landholding Agency: Navy
Property Number: 779710052
Status: Excess
Comment: 144 sq. ft., each, off-site use only

Bldg. 251
Naval Base Norfolk, St. Julien's Creek Annex Co: Chesapeake VA
Landholding Agency: Navy
Property Number: 779710053
Status: Excess
Comment: 1134 sq. ft., off-site use only

Bldg. 254
Naval Base Norfolk, St. Julien's Creek Annex Co: Chesapeake VA
Landholding Agency: Navy
Property Number 779710054
Status: Excess
Comment: 156 sq. ft., off-site use only

Bldg. 280
Naval Base Norfolk, St. Julien's Creek Annex Co: Chesapeake VA
Landholding Agency: Navy
Property Number: 779710055
Status: Excess
Comment: 126 sq. ft., off-site use only

Bldg. 357
Naval Base Norfolk, St. Julien's Creek Annex Co: Chesapeake VA
Landholding Agency: Navy
Property Number: 779710056
Status: Excess
Comment: 2214 sq. ft., off-site use only

Bldg. 360
Naval Base Norfolk, St. Julien's Creek Annex Co: Chesapeake VA
Landholding Agency: Navy
Property Number: 779710057
Status: Excess
Comment: 144 sq. ft., off-site use only

Bldg. 383
Naval Base Norfolk, St. Julien's Creek Annex Co: Chesapeake VA
Landholding Agency: Navy
Property Number: 779710058
Status: Excess
Comment: 160 sq. ft., off-site use only

Wisconsin

Bldg. 8
Va Medical Center
County Highway E
Tomah Co: Monroe WI 54660–
Landholding Agency: VA
Property Number: 979010056
Status: Underutilized
Comment: 2200 sq. ft., 2 story wood frame, possible asbestos, potential utilities, structural deficiencies, needs rehab.

Land (by State)

Alabama

VA Medical Center
VAMC
Tuskegee Co: Macon AL 36083–
Landholding Agency: VA
Property Number: 979010053
Status: Underutilized
Comment: 40 acres, buffer to VA Medical Center, potential utilities, undeveloped.

California

Land
4150 Clement Street
San Francisco Co: San Francisco CA 94121–
Landholding Agency: VA
Property Number: 979240001
Status: Underutilized
Comment: 4 acres; landslide area.

Georgia

Naval Submarine Base
Grid R–2 to R–3 to V–4 to V–1
Kings Bay Co: Camden GA 31547–
Landholding Agency: Navy
Property Number: 779010229
Status: Underutilized
Comment: 111.57 acres; areas may be environmentally protected; secured area with alternate access.

Maryland

VA Medical Center
9500 North Point Road
Fort Howard Co: Baltimore MD 21052–
Landholding Agency: VA
Property Number: 979010020
Status: Underutilized
Comment: Approx. 10 acres, wetland and periodically floods, most recent use-dump site for leaves.

Oregon

1–C Drain Right-of-Way
Klamath Project
Klamath Falls Co: Klamath OR 97603–
Landholding Agency: Interior
Property Number: 61920002
Status: Unutilized
Comment: 0.51 acres, narrow strip of land

Texas

Peary Point #2
Naval Air Station
Corpus Christi Co: Nueces TX 78419–5000
Landholding Agency: Navy
Property Number: 779030001
Status: Excess
Comment: 43.48 acres; 60% of land under lease until 8/93.
GSA Number: 7–N–TX–402–V

Land
Olin E. Teague Veterans Center
1901 South 1st Street
Temple Co: Bell TX 76504–
Landholding Agency: VA
Property Number: 979010079
Status: Underutilized
Comment: 13 acres, portion formerly landfill, portion near flammable materials, railroad crosses property, potential utilities.

VA. Medical Center
4800 Memorial Drive
Waco Co: McLennan TX 76711–
Landholding Agency: VA
Property Number: 979010081
Status: Underutilized
Comment: 2.3 acres, negotiating lease w/ Owens-Illinois Glass Plant, most recent use—parking lot.

Wisconsin

VA Medical Center
County Highway E
Tomah Co: Monroe WI 54660–
Landholding Agency: VA

Property Number: 979010054
Status: Underutilized
Comment: 12.4 acres, serves as buffer between center and private property, no utilities.

Suitable/Unavailable Properties

Buildings (by State)

California

Bldg. 116
VA Medical Center
Wilshire and Sawtelle Blvds.
Los Angeles Co: Los Angeles CA 90073–
Landholding Agency: VA
Property Number: 979110009
Status: Underutilized
Comment: 60309 sq. ft., 3 story brick frame, seismic reinforcement defics., underutil. port of bldg. used intermitly., needs rehab, poss. asbestos in pipes/floor tiles, site access lim.

Florida

Bldg. 36, VAMC
10,000 Bay Pines Blvd.
Bay Pines Co: Pinellas FL 33504–
Landholding Agency: VA
Property Number: 979230009
Status: Underutilized
Comment: portion of 15,984 sq. ft., 1 story concrete frame bldg., needs rehab, presence of asbestos, listed on Natl Register of Historic Places, access restrictions.

Bldg. 37, VAMC
10,000 Bay Pines Blvd.
Bay Pines Co: Pinellas FL 33504–
Landholding Agency: VA
Property Number: 979230010
Status: Underutilized
Comment: Third floor of a concrete frame bldg. (13,900 sq. ft.), presence of asbestos, listed on Natl Register of Historic Places, access restrictions.

Hawaii

Bldgs. S898, S899
Naval Station, Mauka Side
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779630078
Status: Excess
Comment: 1320 sq. ft. each, concrete, needs rehab, most recent use—bomb shelters, off-site use only

Bldg. 1251
Naval Station, Ward Field
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779630079
Status: Excess
Comment: 374 sq. ft., concrete foundation and walls, needs rehab, off-site use only

Bldg. 26
Naval Station, Beckoning Point
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779630080
Status: Excess
Comment: 4284 sq. ft., lumber construction, needs rehab, most recent use—office, off-site use only

Bldg. 1208
Naval Station, Nauka Side
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779630081
Status: Excess
Comment: 558 sq. ft., concrete, most recent use—office, needs rehab, off-site use only

Bldg. 1494
Naval Station, Mauka Side
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779630089
Status: Excess
Comment: 560 sq. ft., concrete, needs rehab, most recent use—storage, off-site use only

Indiana

Bldg. 24, VAMC
East 38th Street
Marion Co: Grant IN 46952–
Landholding Agency: VA
Property Number: 979230005
Status: Underutilized
Comment: portion of 4135 sq. ft. 2-story wood structure, needs major rehab, no sanitary or heating facilities, presence of asbestos, access restrictions.

Bldg. 105, VAMC
East 38th Street
Marion Co: Grant IN 46952–
Landholding Agency: VA
Property Number: 979230006
Status: Underutilized
Comment: 310 sq. ft., 1 story stone structure, needs major rehab, no sanitary or heating facilities, access restrictions.

Maine

Bldg. 376, Naval Air Station
Topsham Annex
Topsham Co: Sagadahoc ME
Landholding Agency: Navy
Property Number: 779320011
Status: Unutilized
Comment: 4530 sq. ft., 2-story, most recent use—quarters, needs rehab

Maryland

Bldg. 230
Naval Communication Detachment
9190 Commo Road
Cheltenham Co: Prince George MD 20397–5520
Landholding Agency: Navy
Property Number: 779330010
Status: Unutilized
Comment: 12,384 sq. ft., 4-story, needs rehab, potential utilities, includes 37 acres of land

Minnesota

Bldg. 227
VA Medical Center
Fort Snelling
St. Paul Co: Hennepin MN 55111–
Landholding Agency: VA
Property Number: 979010033
Status: Unutilized
Comment: 850 sq. ft., 2 story wood frame and brick residence, utilities disconnected.

New York

Bldg. 144, VAECC
Linden Blvd. and 179th St.
St. Albans Co: Queens NY 11425–
Landholding Agency: VA
Property Number: 979210004
Status: Unutilized
Comment: 5215 sq. ft., 2 story wood frame residence, needs rehab, potential utilities

Bldg. 143, VAECC
Linden Blvd. and 179th St.
St. Albans Co: Queens NY 11425–
Landholding Agency: VA
Property Number: 979210005
Status: Unutilized
Comment: 5215 sq. ft., 2 story wood frame residence, needs rehab, potential utilities

Bldgs. 142/146, VAECC
Linden Blvd. and 179th St.
St. Albans Co: Queens NY 11425–
Landholding Agency: VA
Property Number: 979210006
Status: Unutilized
Comment: 5215 sq. ft., 2 story wood frame residence with 380 sq. ft. attached garage, needs rehab, potential utilities

Ohio

Naval & Marine Corps Res. Cntr
315 East LaClede Avenue
Youngstown OH
Landholding Agency: Navy
Property Number: 779320012
Status: Unutilized
Comment: 3067 sq. ft. 2 story, possible asbestos.

Pennsylvania

Bldg. 2, VAMC
1700 South Lincoln Avenue
Lebanon Co: Lebanon PA 17042–
Landholding Agency: VA
Property Number: 979230011
Status: Underutilized
Comment: portion of 16,360 sq. ft. 3-story structure, most recent use—storage.

Bldg. 3 VAMC
1700 South Lincoln Avenue
Lebanon Co: Lebanon PA 17042–
Landholding Agency: VA
Property Number: 979230012
Status: Underutilized
Comment: portion of bldg. (3850 and 4360 sq. ft.), most recent use—storage.

Bldg. 103, VAMC
1700 South Lincoln Avenue
Lebanon Co: Lebanon PA 17042–
Landholding Agency: VA
Property Number: 979230014
Status: Underutilized
Comment: portion of 1215 sq. ft. 2-story stone farm house, needs repair.

Puerto Rico

Bldgs. 501 & 502
U.S. Naval Radio Transmitter Facility
State Road No. 2
Juana Diaz PR 00795–
Landholding Agency: Navy
Property Number: 779530007
Status: Underutilized
Comment: Reinforced concrete structures, limited access, needs rehab, most recent use—transmitter and power house.

Bldg. 561
Former Ramey AFB
Aguadilla PR 00604–
Landholding Agency: Navy
Property Number: 779630001
Status: Unutilized
Comment: 10266 sq. ft. bldg. on 12.287 acres, most recent use—manufacturing, office and freight distribution center, presence of asbestos.

Texas

Bldg. 2435

Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010161
Status: Underutilized
Comment: 1730 sq. ft.; 1 story residence.

Bldg. 2436
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010162
Status: Underutilized
Commens: 3352 sq. ft.; 1 story residence.

Bldg. 2460
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010163
Status: Underutilized
Comment: 1758 sq. ft.; 1 story residence.

Bldg. 2462
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010164
Status: Underutilized
Comment: 1758 sq. ft.; 1 story residence.

Bldg. 2464
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010165
Status: Underutilized
Comment: 1758 sq. ft.; 1 story residence.

Bldg. 2466
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010166
Status: Underutilized
Comment: 1576 sq. ft.; 1 story residence.

Bldg. 2467
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010167
Status: Underutilized
Comment: 3532 sq. ft.; 1 story residence.

Bldg. 2468
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010168
Status: Underutilized
Comment: 1758 sq. ft.; 1 story residence.

Bldg. 2472
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010169
Status: Underutilized
Comment: 1758 sq. ft.; 1 story residence.

Bldg. 2476
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010170
Status: Underutilized
Comment: 1758 sq. ft.; 1 story residence.

Bldg. 2482
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010171
Status: Underutilized
Comment: 1760 sq. ft.; 1 story residence.

Bldg. 2495
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010172
Status: Underutilized
Comment: 1760 sq. ft.; 1 story residence.

Bldg. 2514
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010173
Status: Underutilized
Comment: 1730 sq. ft.; 1 story residence.

Bldg. 2518
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010174
Status: Underutilized
Comment: 1676 sq. ft.; 1 story residence.

Bldg. 2520
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010175
Status: Underutilized
Comment: 1676 sq. ft.; 1 story residence.

Bldg. 2522
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010176
Status: Underutilized
Comment: 1676 sq. ft.; 1 story residence.

Bldg. 2526
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010177
Status: Underutilized
Comment: 1676 sq. ft.; 1 story residence.

Bldg. 2423
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010178
Status: Underutilized
Comment: 3532 sq. ft.; 1 story residence.

Bldg. 2427
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010179
Status: Underutilized
Comment: 3532 sq. ft.; 1 story residence.

Bldg. 2431
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010180
Status: Underutilized
Comment: 3532 sq. ft.; 1 story residence.

Bldg. 2424
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010181
Status: Underutilized
Comment: 3352 sq. ft.; 1 story residence.

Bldg. 2433
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010182
Status: Underutilized
Comment: 3352 sq. ft.; 1 story residence.

Bldg. 2428
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010183
Status: Underutilized
Comment: 3352 sq. ft.; 1 story residence.

Bldg. 2429
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010184
Status: Underutilized
Comment: 3152 sq. ft.; 1 story residence.

Bldg. 2454
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010185
Status: Underutilized
Comment: 3152 sq. ft.; 1 story residence.

Bldg. 2477
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010186
Status: Underutilized
Comment: 3152 sq. ft.; 1 story residence.

Bldg. 2485
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010187
Status: Underutilized
Comment: 3152 sq. ft.; 2 story residence.

Bldg. 2499
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010188
Status: Underutilized

Comment: 3152 sq. ft.; 1 story residence.
Bldg. 2503
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010189
Status: Underutilized
Comment: 3152 sq. ft.; 1 story residence.
Bldg. 2507
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010190
Status: Underutilized
Comment: 3152 sq. ft.; 1 story residence.
Bldg. 2513
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010191
Status: Underutilized
Comment: 3152 sq. ft.; 1 story residence.
Bldg. 2521
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010192
Status: Underutilized
Comment: 3152 sq. ft.; 1 story residence.
Bldg. 2451
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010193
Status: Underutilized
Comment: 1758 sq. ft., 1 story residence.
Bldg. 2458
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010194
Status: Underutilized
Comment: 1758 sq. ft., 1 story residence.
Bldg. 2461
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010195
Status: Underutilized
Comment: 1758 sq. ft., 1 story residence.
Bldg. 2473
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010196
Status: Underutilized
Comment: 1758 sq. ft., 1 story residence.
Bldg. 2478
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010197
Status: Underutilized
Comment: 1758 sq. ft., 1 story residence.
Bldg. 2480
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010198
Status: Underutilized
Comment: 1758 sq. ft., 1 story residence.
Bldg. 2484
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010199
Status: Underutilized
Comment: 1758 sq. ft., 1 story residence.
Bldg. 2486
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010200
Status: Underutilized
Comment: 1758 sq. ft., 1 story residence.
Bldg. 2487
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010201
Status: Underutilized
Comment: 1758 sq. ft., 1 story residence.
Bldg. 2488
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010202
Status: Underutilized
Comment: 1758 sq. ft., 1 story residence.
Bldg. 2494
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010203
Status: Underutilized
Comment: 1758 sq. ft., 1 story residence.
Bldg. 2500
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010204
Status: Underutilized
Comment: 1758 sq. ft., 1 story residence.
Bldg. 2502
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010205
Status: Underutilized
Comment: 1758 sq. ft., 1 story residence.
Bldg. 2506
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010206
Status: Underutilized
Comment: 1758 sq. ft., 1 story residence.
Bldg. 2508
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010207
Status: Underutilized
Comment: 1758 sq. ft., 1 story residence.
Bldg. 2525
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010208
Status: Underutilized
Comment: 1758 sq. ft.; 1 story residence.
Bldg. 2452
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010209
Status: Underutilized
Comment: 3356 sq. ft.; 1 story residence.
Bldg. 2475
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010210
Status: Underutilized
Comment: 3356 sq. ft.; 1 story residence.
Bldg. 2479
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010211
Status: Underutilized
Comment: 3356 sq. ft.; 1 story residence.
Bldg. 2497
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010212
Status: Underutilized
Comment: 3356 sq. ft.; 1 story residence.
Bldg. 2501
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010213
Status: Underutilized
Comment: 3356 sq. ft.; 1 story residence.
Bldg. 2505
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010214
Status: Underutilized
Comment: 3356 sq. ft.; 1 story residence.
Bldg. 2515
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010215
Status: Underutilized
Comment: 3356 sq. ft.; 1 story residence.
Bldg. 2517
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy

Property Number: 779010216
Status: Underutilized
Comment: 3356 sq. ft.; 1 story residence.

Bldg. 2519
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010217
Status: Underutilized
Comment: 3356 sq. ft.; 1 story residence.

Bldg. 2523
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010218
Status: Underutilized
Comment: 3356 sq. ft.; 1 story residence.

Bldg. 2465
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010219
Status: Underutilized
Comment: 1576 sq. ft.; 1 story residence.

Bldg. 2493
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010220
Status: Underutilized
Comment: 1576 sq. ft.; 1 story residence.

Bldg. 2510
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010221
Status: Underutilized
Comment: 1576 sq. ft.; 1 story residence.

Bldg. 2474
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010222
Status: Underutilized
Comment: 3528 sq. ft.; 1 story residence.

Bldg. 2481
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010223
Status: Underutilized
Comment: 3528 sq. ft.; 1 story residence.

Bldg. 2509
Laguna Housing Area
NAS Corpus Chiristi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010224
Status: Underutilized
Comment: 1676 sq. ft.; 1 story residence.

Bldg. 2511
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010225
Status: Underutilized
Comment: 1676 sq. ft.; 1 story residence.

Bldg. 2512
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010226
Status: Underutilized
Comment: 1676 sq. ft.; 1 story residence.

Bldg. 2527
Laguna Housing Area
NAS Corpus Christi
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010227
Status: Underutilized
Comment: 1676 sq. ft.; 1 story residence.

Virginia

Naval Medical Clinic
6500 Hampton Blvd.
Norfolf Co: Norfolk VA 23508–
Landholding Agency: Navy
Property Number: 779010109
Status: Unutilized
Comment: 3665 sq. ft., 1 story, possible asbestos, most recent use-laundry.

Bldg. X353
Naval Station
1802 Powhatan Street
Norfolk VA 23511–
Landholding Agency: Navy
Property Number: 779640016
Status: Unutilized
Comment: 4710 sq. ft., 2-story, most recent use—admin., off-site use only

Wyoming

Bldg. 13
Medical Center
N.W. of town at the end of fort Road
Sheridan Co: Sheridan WY 82801–
Landholding Agency: VA
Property Number: 979110001
Status: Unutilized
Comment: 3613 sq. ft., 3 story wood frame masonry veneered, potential utilities, possible asbestos, needs rehab.

Bldg. 79
Medical Center
N.W. of town at the end of Fort Road
Sheridan Co: Sheridan WY 82801–
Landholding Agency: VA
Property Number: 979110003
Status: Unutilized
Comment: 45 sq. ft., 1 story brick and tile frame, limited utilities, most recent use—reservoir house, use for storage purposes.

Land (by State)

Arizona

Tract No. APO–SRP–RB–5
Mesa Co: Maricopa AZ 85213–
Location: 2000′ south of Thomas Road at Val Vista Drive
Landholding Agency: Interior
Property Number: 619410005
Status: Unutilized
Comment: 0.57 acre; 20 foot strip of land which is 1,026 ft. long

Quartermaster Depot
4th Avenue and Colorado River
Yuma Co: Yuma AZ 85364–
Landholding Agency: Interior
Property Number: 619420001
Status: Underutilized
Comment: Less than 1 acre, dirt and shrubbery along the river, lease restrictions, historical site

ACDC Tract No. T–71A
Along the Arizona Canal
Glendale Co: Maricopa AZ 85306–
Landholding Agency: Interior
Property Number: 619530001
Status: Excess
Comment: 3.15 acres

Tract No. OSG–1–23
Near McDowell Road & Bush Hwy.
Mesa Co: Maricopa AZ 85207–
Landholding Agency: Interior
Property Number: 619530012
Status: Excess
Comment: 0.29 acres, located next to private land owner, limited access

California

Folsom South Canal
SW corner of Whiterock Rd. & Folsom S Canal
Rancho Cordova Co: Sacramento CA 95670–
Landholding Agency: Interior
Property Number: 619310002
Status: Excess
Comment: 1.52 acres; perpetual easement over .25 acre, surrounding land use is commercial

Florida

Naval Public Works Center
Naval Air Station
Pensacola Co: Escambia FL 32508–
Location: Southeast corner of Corey station—next to family housing.
Landholding Agency: Navy
Property Number: 779010157
Status: Unutilized
Comment: 22 acres

Compound, VAMC
10,000 Bay Pines Blvd.
Bay Pines Co: Pinellas FL 33504–
Landholding Agency: VA
Property Number: 979230017
Status: Underutilized
Comment: approx. 7 acres, storage compound, partially wooded

Georgia

Naval Submarine Base
Grid AA–1 to AA–4 to EE–7 to FF–2
Kings Bay Co: Camden GA 31547–
Landholding Agency: Navy
Property Number: 779010255
Status: Underutilized
Comment: 495 acres; 86 acre portion located in floodway; secured area with alternate access.

Illinois

Va Medical Center
3001 Green Bay Road
North Chicago Co: Lake IL 60064–
Landholding Agency: VA
Property Number: 979010082
Status: Underutilized
Comment: 2.5 acres, currently being used as a construction staging area for the next 6–8 years, potential utilities.

Michigan

Va Medical Center
5500 Armstrong Road
Battle Creek Co: Calhoun MI 49016–
Landholding Agency: VA

Property Number: 979010015
Status: Underutilized
Comment: 20 acres, used as exercise trails and storage areas, potential utilities.

Minnesota

Bldg. 227–229 Land
VA Medical Center
Fort Snelling
St Paul Co: Hennepin MN 55111–
Landholding Agency: VA
Property Number: 979010006
Status: Underutilized
Comment: 2.0 acres, potential utilities, buildings occupied, residence/garage.

VA Medical Center
Near 5629 Minnehaha Avenue
Minneapolis Co: Hennepin MN 55417–
Location: Land (Site of Building 15, 16, 21, 48, 64, T10)
Landholding Agency: VA
Property Number: 979010024
Status: Underutilized
Comment: 12.1 acres, most recent use—parking, potential utilities.

Land—12 acres
VAMC
Near 5629 Minnehaha Avenue
Minneapolis Co: Hennepin MN 55417–
Landholding Agency: VA
Property Number: 979010031
Status: Unutilized
Comment: 12 acres, possible asbestos, leased to Department of Natural Resources as a park walking trail.

New York

VA Medical Center
Fort Hill Avenue
Canandaigua Co: Ontario NY 14424–
Landholding Agency: VA
Property Number: 979010017
Status: Underutilized
Comment: 27.5 acres, used for school ballfield and parking, existing utilities easements, portion leased.

Pennsylvania

VA Medical Center
New Castle Road
Butler Co: Butler PA 16001–
Landholding Agency: VA
Property Number: 979010016
Status: Underutilized
Comment: Approx. 9.29 acres, used for patient recreation, potential utilities.

Land No. 645
VA Medical Center
Highland Drive
Pittsburgh Co: Allegheny PA 15206–
Location: Between Campania and Wiltsie Streets
Landholding Agency: VA
Property Number: 979010080
Status: Unutilized
Comment: 90.3 acres, heavily wooded, property includes dump area and numerous site storm drain outfalls.

Land—34.16 acres
VA Medical Center
1400 Black Horse Hill Road
Coatesville Co: Chester PA 19320–
Landholding Agency: VA
Property Number: 979340001
Status: Underutilized
Comment: 34.16 acres, open field, most recent use—recreation/buffer

Virgin Islands

Ham's Bluff Test Site
Freddriksted Co: St. Croix VI 00840–
Landholding Agency: Navy
Property Number: 779530006
Status: Unutilized
Comment: 22.5 acres, bldg. construction underway, secured area w/alternate access, property reverts to Transportation when Navy vacates

Virginia

Naval Base
Norfolk Co: Norfolk VA 23508–
Location: Northeast corner of base, near Willoughby housing area.
Landholding Agency: Navy
Property Number: 779010156
Status: Unutilized
Comment: 60 acres; most recent use—sandpit; secured area with alternate access.

Suitable/To Be Excessed

Buildings (by State)

California

Bldg. 100
Naval Facilities Point Sur
CVB Detachment
Monterey Co: Monterey CA 93940–
Landholding Agency: Navy
Property Number: 779010259
Status: Unutilized
Comment: 2628 sq. ft.; 1 story permanent bldg; possible asbestos; secure facility with alternate access; use—office space.

Bldg. 102
Naval Facilities Point Sur
CVB Detachment
Monterey Co: Monterey CA 93940–
Landholding Agency: Navy
Property Number: 779010260
Status: Unutilized
Comment: 580 sq. ft.; 1 story permanent bldg; possible asbestos; secure facility with alternate access; most recent use—office.

Bldg. 103
Naval Facilities Point Sur
CVB Detachment
Monterey Co: Monterey CA 93940–
Landholding Agency: Navy
Property Number: 779010261
Status: Unutilized
Comment: 3675 sq. ft.; 1 story permanent bldg; possible asbestos; secure facility with alternate access; most recent use—dining hall.

Bldg. 109
Naval Facilities Point Sur
CVB Detachment
Monterey Co: Monterey CA 93940–
Landholding Agency: Navy
Property Number: 779010262
Status: Unutilized
Comment: 1045 sq. ft.; 2 story permanent bldg; possible asbestos; secure facility with alternate access; most recent use—barracks.

Bldg. 110
Naval Facilities Point Sur
CVB Detachment
Monterey Co: Monterey CA 93940–
Landholding Agency: Navy
Property Number: 779010263
Status: Unutilized
Comment: 4439 sq. ft.; 1 story permanent bldg; possible asbestos; secure facility with alternate access; most recent use—shop.

Bldg. 113
Naval Facilities Point Sur
CVB Detachment
Monterey Co: Monterey CA 93940–
Landholding Agency: Navy
Property Number: 779010264
Status: Unutilized
Comment: 100 sq. ft.; 1 story permanent bldg; secured facility with alternate access; most recent use—storage.

Bldg. 138
Naval Facilities Point Sur
CVB Detachment
Monterey Co: Monterey CA 93940–
Landholding Agency: Navy
Property Number: 779010265
Status: Unutilized
Comment: 110 sq. ft.; 1 story permanent bldg; possible asbestos; secure facility with alternate access; most recent use—filling station.

Bldg. 144
Naval Facilities Point Sur
CVB Detachment
Monterey Co: Monterey CA 93940–
Landholding Agency: Navy
Property Number: 779010266
Status: Unutilized
Comment: 4320 sq. ft.; 1 story semi-permanent bldg; possible asbestos; secure facility with alternate access; most recent use—bowling alley.

Bldg. 145
Naval Facilities Point Sur
CVB Detachment
Monterey Co: Monterey CA 93940–
Landholding Agency: Navy
Property Number: 779010267
Status: Unutilized
Comment: 4000 sq. ft.; 1 story semi-permanent bldg; possible asbestos, secure facility with alternate access; most recent use—recreation building.

New Hampshire

Naval & Marine Corp. Rsv. Ctr.
199 North Main St.
Manchester NH 03102–
Landholding Agency: Navy
Property Number: 779530005
Status: Excess
Comment: 3 bldgs. on 2.53 acres of land, limited utilities, limited use prior to environmental cleanup

Washington

Quarters No. 1204
604 S. Maple
Warden Co: Grant WA 98857–
Landholding Agency: Interior
Property Number: 619330001
Status: Excess
Comment: 850 sq. ft., one story frame residence, asbestos siding

Quarters No. 1208
608 S. Maple
Warden Co: Grant WA 98857–
Landholding Agency: Interior
Property Number: 619330002
Status: Excess
Comment: 709 sq. ft., one story frame residence, asbestos siding

Quarters No. 1301

3 SE and N Warden Road
Warden Co: Grant WA 98857–
Landholding Agency: Interior
Property Number: 619330003
Status: Excess
Comment: 709 sq. ft., one story frame residence on 4.9 acres, asbestos siding

Land (by State)

Illinois

Libertyville Training Site
Libertyville Co: Lake IL 60048–
Landholding Agency: Navy
Property Number: 779010073
Status: Excess
Comment: 114 acres; possible radiation hazard; existing FAA use license.

Minnesota

Land around Bldg. 240–249, 253
VA Medical Center
Fort Snelling
St Paul Co: Hennepin MN 55111–
Landholding Agency: VA
Property Number: 979010007
Status: Unutilized
Comment: 3.76 acres, potential utilities.

Unsuitable Properties

Buildings (by State)

Alaska

Sand Shed, Map Grid 45024
Naval Air Station
Adak Co: Adak AK 98791–
Landholding Agency: Navy
Property Number: 77912004
Status: Unutilized
Reason: Secured Area

LORAN Station, Map Grid 09L11
Naval Air Station
Adak Co: Adak AK 98791–
Landholding Agency: Navy
Property Number: 779120006
Status: Unutilized
Reason: Secured Area

Bldg. 10196
Naval Security Group Activity
Adak Co: Adak AK 98791–
Landholding Agency: Navy
Property Number: 779310021
Status: Unutilized
Reason: Secured Area

Bldg. 10517
Naval Security Group Activity
Adak Co: Adak AK 98791–
Landholding Agency: Navy
Property Number: 779310022
Status: Unutilized
Reason: Secured Area

Bldg. 10518
Naval Security Group Activity
Adak Co: Adak AK 98791–
Landholding Agency: Navy
Property Number: 779310023
Status: Unutilized
Reason: Secured Area

Bldg. 10535
Naval Security Group Activity
Adak Co: Adak AK 98791-
Landholding Agency: Navy
Property Number: 779310024
Status: Unutilized
Reason: Secured Area

Bldg. 10538
Naval Security Group Activity
Adak Co: Adak AK 98791-
Landholding Agency: Navy
Property Number: 779310025
Status: Unutilized
Reason: Secured Area

Bldg. 10539
Naval Security Group Activity
Adak Co: Adak AK 98791-
Landholding Agency: Navy
Property Number: 779310026
Status: Unutilized
Reason: Secured Area

Bldg. 10540
Naval Security Group Activity
Adak Co: Adak AK 98791-
Landholding Agency: Navy
Property Number: 779310027
Status: Unutilized
Reason: Secured Area

Bldg. 10603
Naval Security Group Activity
Adak Co: Adak AK 98791-
Landholding Agency: Navy
Property Number: 779310028
Status: Unutilized
Reason: Secured Area

Generator Bldg.
Naval Security Group Activity
Adak Island AK
Landholding Agency: Navy
Property Number: 779430017
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Arizona

Inn Cabin #9
North Rim Grand Canyon
Grand Canyon Co: Coconino AZ 86023-
Landholding Agency: Interior
Property Number: 619530013
Status: Unutilized
Reason: Extensive deterioration

California

Bldg. 06437
Vandenberg Air Force Base
Vandenberg AFB Co: Santa Barbara CA 93437-
Landholding Agency: Air Force
Property Number: 189710014
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 09326
Vandenberg Air Force Base
Vandenberg AFB Co: Santa Barbara CA 93437-
Landholding Agency: Air Force
Property Number: 189710015
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 10715
Vandenberg Air Force Base
Vandenberg AFB Co: Santa Barbara CA 93437-
Landholding Agency: Air Force
Property Number: 189710016
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 13017
Vandenberg Air Force Base
Vandenberg AFB Co: Santa Barbara CA 93437-
Landholding Agency: Air Force
Property Number: 189710017
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 13522
Vandenberg Air Force Base
Vandenberg AFB Co: Santa Barbara CA 93437-
Landholding Agency: Air Force
Property Number: 189710018
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 13607
Vandenberg Air Force Base
Vandenberg AFB Co: Santa Barbara CA 93437-
Landholding Agency: Air Force
Property Number: 189710019
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 21300
Vandenberg Air Force Base
Vandenberg AFB Co: Santa Barbara CA 93437-
Landholding Agency: Air Force
Property Number: 189710020
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 23206
Vandenberg Air Force Base
Vandenberg AFB Co: Santa Barbara CA 93437–
Landholding Agency: Air Force
Property Number: 189710021
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 105
Naval FPS, CVB Detachment
Monterey Co: Monterey CA 93940–
Landholding Agency: Navy
Property Number: 779010159
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material

Bldg. 165
Naval FPS, CVB Detachment
Monterey Co: Monterey CA 93940–
Landholding Agency: Navy
Property Number: 779010160
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material

Bldg. 146
Naval Facilities Point Sur
CVB Detachment
Monterey Co: Monterey CA 93940–
Landholding Agency: Navy
Property Number: 779010268
Status: Unutilized
Reason: Other
Comment: Sewer treatment facility

Bldg. 31104
Naval Air Weapons Station
China Lake Co: San Bernardino CA 93555–
Landholding Agency: Navy
Property Number: 779340003
Status: Unutilized

Reason: Secured Area

Bldg. 311107
Naval Air Weapons Station
China Lake Co: Bernardino CA 93555–
Landholding Agency: Navy
Property Number: 77942001
Status: Unutilized
Reason: Secured Area

Bldg. 15951
Naval Air Weapons Station
China Lake Co: San Bernardino CA 93555–6001
Landholding Agency: Navy
Property Number: 779430006
Status: Unutilized
Reason: Secured Area, Extensive deterioration, Within 2000 ft. of flammable or explosive material

Bldg. 31539
Naval Air Weapons Station
China Lake Co: San Bernardino CA 93555–
Landholding Agency: Navy
Property Number: 779430016
Status: Unutilized
Reason: Within 2000 ft. of flammable explosive material, Secured Area, Extensive deterioration

Bldg. 00366
Naval Air Weapons Station
China Lake Co: Kern CA 93555–
Landholding Agency: Navy
Property Number: 779520001
Status: Excess
Reason: Secured Area

Bldg. 00405
Naval Air Weapons Station
China Lake Co: Kern CA 93555–
Landholding Agency: Navy
Property Number: 779520002
Status: Excess
Reason: Secured Area

Bldg. 00418
Naval Air Weapons Station
China Lake Co: Kern CA 93555–
Landholding Agency: Navy
Property Number: 77952003
Status: Excess
Reason: Secured Area

Bldg. 00421
Naval Air Weapons Station
China Lake Co: Kern CA 93555–
Landholding Agency: Navy
Property Number: 779520004
Status: Excess
Reason: Secured Area

Bldg. 00426
Naval Air Weapons Station
China Lake Co: Kern CA 93555–
Landholding Agency: Navy
Property Number: 779520005
Status: Excess
Reason Secured Area

Bldg. 00427
Naval Air Weapons Station
China Lake Co: Kern CA 93555–
Landholding Agency: Navy
Property Number: 779520006
Status: Excess
Reason: Secured Area

Bldg. 00429
Naval Air Weapons Station
China Lake Co: Kern CA 93555–
Landholding Agency: Navy
Property Number: 779520007
Status: Excess
Reason: Secured Area

Bldg. 00430
Naval Air Weapons Station
China Lake Co: Kern CA 93555–
Landholding Agency: Navy
Property Number: 779520008
Status: Excess
Reason: Secured Area

5 Bldgs.
Naval Air Weapons Station
China Lake Co: Kern CA 93555–
Location: Include: #'s 00360, 00415, 00419, 00423, 00414
Landholding Agency: Navy
Property Number: 779520009
Status: Excess
Reason: Secured Area

5 Bldgs.
China Lake Co: Kern CA 93555–
Location: Include: #'s 00428, 00359, 00362, 00369, 00409
Landholding Agency: Navy
Property Number: 779520010
Status: Excess
Reason: Secured Area

5 Bldgs.
Naval Air Weapons Station
China Lake Co: Kern CA 93555–
Location: Include: #'s 00367, 00416, 00425, 00365, 00368
Landholding Agency: Navy
Property Number: 779520011
Status: Excess
Reason: Secured Area

4 Bldgs.
Naval Air Weapons Station
China Lake Co: Kern CA 93555–
Location: Include #'s 00370, 00371, 00385, 00404
Landholding Agency: Navy
Property Number: 779520012
Status: Excess
Reason: Secured Area

4 Bldgs.
Naval Air Weapons Station
China Lake Co: Kern CA 93555–
Location: Include #'s 00412, 00433, 00434, 00435
Landholding Agency: Navy
Property Number: 779520013
Status: Excess
Reason: Secured Area

Bldgs. 31030, 31031 & 31034
Naval Air Weapons Station
China Lake Co: San Bernardino CA 93555–6001
Landholding Agency: Navy
Property Number: 779520015
Status: Excess
Reason: Secured Area, Within 2000 ft. of flammable or explosive material

Bldg. 481
Naval Air Weapons Station, China Lake
China Lake Co: Kern CA 93555–
Landholding Agency: Navy
Property Number: 779520018
Status: Unutilized
Reason: Secured Area

Bldg. 482
Naval Air Weapons Station, China Lake
China Lake Co: Kern CA 93555–
Landholding Agency: Navy
Property Number: 779520019
Status: Excess
Reason: Secured Area

Bldg. 356
Naval Air Weapons Station, China Lake
China Lake Co: Kern CA 93555–
Landholding Agency: Navy
Property Number: 779520020
Status: Excess
Reason: Secured Area

Bldg. 361
Naval Air Weapons Station, China Lake
China Lake Co: Kern CA 93555–
Landholding Agency: Navy
Property Number: 779520021
Status: Excess
Reason: Secured Area

Bldg. 364
Naval Air Weapons Station, China Lake
China Lake Co: Kern CA 93555–
Landholding Agency: Navy
Property Number: 779520022
Status: Excess
Reason: Secured Area

Bldg. 373
Naval Air Weapons Station, China Lake
China Lake Co: Kern CA 93555–
Landholding Agency: Navy
Property Number: 779520023
Status: Excess
Reason: Secured Area

Bldg. 407
Naval Air Weapons Station, China Lake
China Lake Co: Kern CA 93555–
Landholding Agency: Navy
Property Number: 779520024
Status: Excess
Reason: Secured Area.

Bldg. 413
Naval Air Weapons Station, China Lake
China Lake Co: Kern CA 93555–
Landholding Agency: Navy
Property Number: 779520025
Status: Excess
Reason: Secured Area

Bldg. 366
Naval Air Weapons Station, China Lake
China Lake Co: Kern CA 93555–
Landholding Agency: Navy
Property Number: 779520026
Status: Unutilized
Reason: Secured Area

Bldg. 432
Naval Air Weapons Station, China Lake
China Lake Co: Kern CA 93555–
Landholding Agency: Navy
Property Number: 779520027
Status: Excess
Reason: Secured Area

Bldg. 372
Naval Air Weapons Station, China Lake
China Lake Co: Kern CA 93555–
Landholding Agency: Navy
Property Number: 779520028
Status: Excess
Reason: Secured Area

Bldg. 417
Naval Air Weapons Station, China Lake
China Lake Co: Kern CA 93555–
Landholding Agency: Navy
Property Number: 779520029
Status: Excess
Reason: Secured Area

Bldg. 422
Naval Air Weapons Station, China Lake

China Lake Co: Kern CA 93555–
Landholding Agency: Navy
Property Number: 779520030
Status: Excess
Reason: Secured Area

Bldg. 424
Naval Air Weapons Station, China Lake
China Lake Co: Kern CA 93555–
Landholding Agency: Navy
Property Number: 779520031
Status: Excess
Reason: Secured Area

Bldg. 30735
Naval Air Weapons Center
China Lake Co: Kern CA 93555–
Landholding Agency: Navy
Property Number: 779530029
Status: Excess
Reason: Secured Area

Bldg. 20186
Observation Tower, Naval Air Weapons Station,
China Lake Co: Kern CA 93555–
Landholding Agency: Navy
Property Number: 779540001
Status: Excess
Reason: Extensive deterioration

Bldg. 120
Naval Air Weapons Station, Point Mugu
San Nicholas Island Co: Ventura CA 97042–
Landholding Agency: Navy
Property Number: 779540002
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 122
Naval Air Weapons Station
Point Mugu Co: Ventura CA 93042–
Landholding Agency: Navy
Property Number: 77961001
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 1468
Naval Construction Battalion Center
Port Hueneme Co: Ventura CA 93043–4301
Landholding Agency: Navy
Property Number: 779610002
Status: Underutilized
Reason: Secured Area

Bldg. 1469
Naval Construction Battalion Center
Port Hueneme Co: Ventura CA 93555–6001
Landholding Agency: Navy
Property Number: 779610003
Status: Underutilized
Reason: Secured Area

Bldg. 31035
Naval Weapons Station
China Lake Co: San Bernardino CA 93555-6001
Landholding Agency: Navy
Property Number: 779620036
Status: Excess
Reason: Within 2000 ft. of flammable or explosive material, Secured Area

Bldg. 00358
Naval Air Weapons Station
China Lake Co: Kern CA 93555-
Landholding Agency: Navy
Property Number: 779610046
Status: Unutilized
Reason: Secured Area

Bldg. 00357
Naval Air Weapons Station
China Lake Co: Kern CA 93555–
Landholding Agency: Navy
Property Number: 779620047
Status: Unutilized
Reason: Secured Area

Bldg. 2–43
Naval Air Weapons Station, Point Mugu
Oxnard Co: Ventura CA 93042–5001
Landholding Agency: Navy
Property Number: 779630018
Status: Unutilized
Reason: Secured Area

Bldg. 2–43A
Naval Air Weapons Station, Point Mugu
Oxnard Co: Ventura CA 93042–5001
Landholding Agency: Navy
Property Number: 779630019
Status: Unutilized
Reason: Secured Area

Bldg. 723
Naval Air Weapons Station, Point Mugu
Oxnard Co: Ventura CA 93042–5001
Landholding Agency: Navy
Property Number: 779630020
Status: Unutilized
Reason: Secured Area

Bldg. 330
Naval Air Weapons Station—Point Mugu
Oxnard Co: Ventura CA 93042–5001
Landholding Agency: Navy
Property Number: 779630038
Status: Unutilized
Reason: Extensive deterioration

Bldg. 5–30
Naval Air Weapons Station
Oxnard Co: Ventura CA 93042–
Landholding Agency: Navy
Property Number: 779640011
Status: Unutilized
Reason: Extensive deterioration

Bldg. 305
Naval Air Weapons Station
Oxnard Co: Ventura CA 93042–
Landholding Agency: Navy
Property Number: 779640012
Status: Unutilized
Reason: Extensive deterioration

Bldg. 616
Naval Air Weapons Station
Oxnard Co: Ventura CA 93042–
Landholding Agency: Navy
Property Number: 779640013
Status: Unutilized
Reason: Extensive deterioration

Bldg. 617
Naval Air Weapons Station
Oxnard Co: Ventura CA 93042–
Landholding Agency: Navy
Property Number: 779640014
Status: Unutilized
Reason: Extensive deterioration

Bldg. 618
Naval Air Weapons Station
Oxnard Co: Ventura CA 93042–
Landholding Agency: Navy
Property Number: 779640015
Status: Unutilized
Reason: Extensive deterioration

Bldg. N46
Naval Air Weapons Station, Point Mugu
Oxnard Co: Ventura CA 93042–5001
Landholding Agency: Navy
Property Number: 779710009
Status: Excess
Reason: Secured Area

Bldg. 773
Naval Air Weapons Station, Point Mugu
Oxnard Co: Ventura CA 93042–5001
Landholding Agency: Navy
Property Number: 779710010
Status: Excess
Reason: Secured Area

Connecticut

Former Housatonic Valley
NPS Tract 286–28
New Milford Co: Litchfield CT 06776–
Landholding Agency: Interior
Property Number: 619640004
Status: Unutilized
Reason: Extensive deterioration

Naval Housing—7 Bldgs.
Naval Submarine Base
New London Co: Groton CT
Landholding Agency: Navy
Property Number: 779510001
Status: Unutilized
Reason: Secured Area

Florida

Bldg. 307
Patrick Air Force Base
Patrick AFB Co: Brevard FL
Landholding Agency: Air Force
Property Number: 189710022
Status: Unutilized
Reason: Secured Area

Bldg. 315
Patrick Air Force Base
Patrick AFB Co: Brevard FL
Landholding Agency: Air Force
Property Number: 189710023
Status: Unutilized
Reason: Secured Area

Bldg. 317
Patrick Air Force Base
Patrick AFB Co: Brevard FL
Landholding Agency: Air Force
Property Number: 189710024
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 318
Patrick Air Force Base
Patrick AFB Co: Brevard FL
Landholding Agency: Air Force
Property Number: 189710025
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 324
Patrick Air Force Base
Patrick AFB Co: Brevard FL
Landholding Agency: Air Force
Property Number: 189710026
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Facility No. 1114
Cape Canaveral Air Station
Cape Canaveral AS Co: Brevard FL 32925–
Landholding Agency: Air Force
Property Number: 189710027
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Facility No. 1345
Cape Canaveral Air Station

Cape Canaveral AS Co: Brevard FL 32925–
Landholding Agency: Air Force
Property Number: 189710028
Status: Unutilized
Reason: Secured Area

Facility No. 1346
Cape Canaveral Air Station
Cape Canaveral AS Co: Brevard FL 32925–
Landholding Agency: Air Force
Property Number: 189710029
Status: Unutilized
Reason: Secured Area

Facility No. 1348
Cape Canaveral Air Station
Cape Canaveral AS Co: Brevard FL 32925–
Landholding Agency: Air Force
Property Number: 189710030
Status: Unutilized
Reason: Secured Area

Facility No. 7805
Cape Canaveral Air Station
Cape Canaveral AS Co: Brevard FL 32925–
Landholding Agency: Air Force
Property Number: 189710031
Status: Unutilized
Reason: Secured Area

Facility No. 7850
Cape Canaveral Air Station
Cape Canaveral AS Co: Brevard FL 32925–
Landholding Agency: Air Force
Property Number: 189710032
Status: Unutilized
Reason: Secured Area

Facility No. 10831
Cape Canaveral Air Station
Cape Canaveral AS Co: Brevard FL 32925–
Landholding Agency: Air Force
Property Number: 189710033
Status: Unutilized
Reason: Secured Area

Facility No. 15500
Cape Canaveral Air Station
Cape Canaveral AS Co: Brevard FL 32925–
Landholding Agency: Air Force
Property Number: 189710034
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Facility No. 39764
Cape Canaveral Air Station
Cape Canaveral AS Co: Brevard FL 32925–
Landholding Agency: Air Force
Property Number: 189710035
Status: Unutilized
Reason: Secured Area

Facility No. 70580
Cape Canaveral Air Station
Cape Canaveral AS Co: Brevard FL 32925–
Landholding Agency: Air Force
Property Number: 189710036
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Facility No. 70662
Cape Canaveral Air Station
Cape Canaveral AS Co: Brevard FL 32925–
Landholding Agency: Air Force
Property Number: 189710037
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Facility No. 72920
Cape Canaveral Air Station
Cape Canaveral AS Co: Brevard FL 32925–
Landholding Agency: Air Force
Property Number: 189710038
Status: Unutilized
Reason: Secured Area

East Martello Bunker #1
Naval Air Station
Key West Co: Monroe FL 33040–
Landholding Agency: Navy
Property Number: 779010101
Status: Excess
Reason: Within airport runway clear zone

Georgia

Naval Submarine Base-Kings Bay
1011 USS Daniel Boone Avenue
Kings Bay Co: Camden GA 31547–
Landholding Agency: Navy
Property Number: 779010107
Status: Unutilized
Reason: Secured Area

Hawaii

Bldg. 126, Naval Magazine
Waikele Branch
Lualualei Co: Oahu HI 96792–
Landholding Agency: Navy
Property Number: 779230012
Status: Unutilized
Reason: Secured Area, Within 2000 ft. of flammable or explosive material, Other
Comment: Extensive Deterioration

Bldg. Q75, Naval Magazine
Lualualei Branch
Lualualei Co: Oahu HI 96792–
Landholding Agency: Navy
Property Number: 779230013
Status: Unutilized
Reason: Secured Area, Other
Comment: Extensive Deterioration

Bldg. 7, Naval Magazine
Lualualei Branch
Lualualei Co: Oahu HI 96792–
Landholding Agency: Navy
Property Number: 779230014
Status: Unutilized
Reason: Secured Area, Other
Comment: Extensive Deterioration

Facility 5985
Naval Station Pearl Harbor
Honolulu Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779310086
Status: Excess
Reason: Extensive Deterioration

Bldg. 6, Pearl Harbor
Richardson Recreational Area
Honolulu Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779410003
Status: Unutilized
Reason: Extensive deterioration

Bldg. 10, Pearl Harbor
Richardson Recreational Area
Honolulu Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779410004
Status: Unutilized
Reason: Extensive deterioration

Bldg. 9
Navy Public Works Center
Kolekole Road
Lualualei Co: Honolulu HI 96782–
Landholding Agency: Navy
Property Number: 779530009
Status: Excess
Reason: Secured Area, Within 2000 ft. of flammable or explosive material

Bldg. X5
Nanumea Road
Pearl Harbor Co: Honolulu HI 96782–
Landholding Agency: Navy
Property Number: 779530010
Status: Excess
Reason: Secured Area

Bldg. SX30
Nanumea Road
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779530011
Status: Excess
Reason: Secured Area

Bldg. 98
Pearl Harbor Naval Shipyard
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779620032
Status: Excess
Reason: Extensive deterioration

Bldg. 309, Naval Station
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779630026
Status: Excess
Reason: Extensive deterioration

Bldg. 314, Naval Station
Ford Island
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779630027
Status: Excess
Reason: Extensive deterioration

Bldg. 307, Naval Station
Ford Island
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779630028
Status: Unutilized
Reason: Extensive deterioration

Bldg. 315, Naval Station
Ford Island
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779630029
Status: Unutilized
Reason: Extensive deterioration

Bldg. 441, Naval Station
Ford Island
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779630030
Status: Unutilized
Reason: Extensive deterioration

Bldg. 4
Naval Station, Ford Island
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779640030
Status: Unutilized
Reason: Extensive deterioration

Bldg. 190
Naval Station, Ford Island
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779640031
Status: Unutilized
Reason: Extensive deterioration

Bldg. 310
Naval Station, Ford Island
Pearl Harbor Co: Honolulu HI 96860–

Landholding Agency: Navy
Property Number: 779640032
Status: Unutilized
Reason: Extensive deterioration

Bldg. S294
Naval Station, Ford Island
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779640033
Status: Unutilized
Reason: Extensive deterioration

Bldg. 593
Naval Station, Halawa Landing Area
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779640034
Status: Unutilized
Reason: Extensive deterioration

Bldg. Q13
Naval Station, Ford Island
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779640035
Status: Unutilized
Reason: Extensive deterioration

Bldg. Q14
Naval Station, Ford Island
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779640036
Status: Unutilized
Reason: Extensive deterioration

Bldg. 591
Naval Station, Halawa Landing Area
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779640037
Status: Unutilized
Reason: Extensive deterioration

Bldg. 592
Naval Station, Halawa Landing Area
Pearl Harbor Co: Honolulu HI 96860–
Landholding Agency: Navy
Property Number: 779640038
Status: Unutilized
Reason: Extensive deterioration

Illinois

Bldg. 928
Naval Training Center
Great Lakes
Great Lakes Co: Lake IL 60088–
Landholding Agency: Navy
Property Number: 779010120
Status: Underutilized
Reason: Secured Area

Bldg. 28
Naval Training Center
Great Lakes
Great Lakes Co: Lake IL 60088–
Landholding Agency: Navy
Property Number: 779010123
Status: Unutilized
Reason: Secured Area

Bldg. 25
Naval Training Center
Great Lakes
Great Lakes Co: Lake IL 60088–
Landholding Agency: Navy
Property Number: 779010126
Status: Unutilized
Reason: Secured Area

South Wing—Building No. 62
Great Lakes Co: Lake IL 60088–5000
Landholding Agency: Navy
Property Number: 779110001
Status: Underutilized
Reason: Secured Area

Bldg. 235
Naval Training Center
Great Lakes Co: Lake IL
Landholding Agency: Navy
Property Number: 779310039
Status: Unutilized
Reason: Secured Area

Bldg. 2B
Naval Training Center
Great Lakes Co: Lake IL
Landholding Agency: Navy
Property Number: 7799310040
Status: Unutilized
Reason: Secured Area

Bldg. 90
Naval Training Center
Great Lakes Co: Lake IL
Landholding Agency: Navy
Property Number: 779310041
Status: Unutilized
Reason: Secured Area

Bldg. 232
Naval Training Center
Great Lakes Co: Lake IL
Landholding Agency: Navy
Property Number: 779310042
Status: Unutilized
Reason: Secured Area

Bldg. 233
Naval Training Center
Great Lakes Co: Lake IL
Landholding Agency: Navy
Property Number: 779310043
Status: Unutilized
Reason: Secured Area

Bldg. 234
Naval Training Center
Great Lakes Co: Lake IL
Landholding Agency: Navy
Property Number: 779310044
Status: Unutilized
Reason: Secured Area

Indiana

Bldg. 21, VA Medical Center
East 38th Street
Marion Co: Grant IN 46952–
Landholding Agency: VA
Property Number: 979230001
Status: Underutilized
Reason: Extensive deterioration

Bldg. 22, VA Medical Center
East 38th Street
Marion Co: Grant IN 46952–
Landholding Agency: VA
Property Number: 979230002
Status: Underutilized
Reason: Extensive deterioration

Bldg. 62, VA Medical Center
East 38th Street
Marion Co: Grant IN 46952–
Landholding Agency: VA
Property Number: 979230003
Status: Underutilized
Reason: Extensive deterioration

Maine

Former Pullen Cabin
NPS Tract 106–29
Monson/Elliottsville Co: Piscataquis ME 04464–
Landholding Agency: Interior
Property Number: 619640001
Status: Unutilized
Reason: Extensive deterioration

Former Mudge Cabin
NPS Tract 106–28
Monson/Elliottsville Co: Piscataquis ME 04464–
Landholding Agency: Interior
Property Number: 619640002
Status: Unutilized
Reason: Extensive deterioration

Former Great Northern Paper
NPS Tract 103–01
Millinocket Co: Piscataquis ME 04462–
Landholding Agency: Interior
Property Number: 619640003
Status: Unutilized
Reason: Extensive deterioration

Bldg. 293, Naval Air Station
Brunswick Co: Cumberland ME 04011–
Landholding Agency: Navy
Property Number: 779240015
Status: Excess
Reason: Secured Area

Bldg. 384
Naval Air Station Topsham
Brunswick Co: Sagadahoc ME
Landholding Agency: Navy
Property Number: 779340001
Status: Unutilized
Reason: Extensive deterioration

Mississippi

Bldg. 6, Boiler Plant
Biloxi VA Medical Center
Biloxi Co: Harrison MS 39531–
Landholding Agency: VA
Property Number: 979410001
Status: Unutilized
Reason: Floodway

Bldg. 67
Biloxi VA Medical Center
Biloxi Co: Harrison MS 39531–
Landholding Agency: VA
Property Number: 979410008
Status: Unutilized
Reason: Extensive deterioration

Bldg. 68
Biloxi VA Medical Center
Biloxi Co: Harrison MS 39531–
Landholding Agency: VA
Property Number: 979410009
Status: Unutilized
Reason: Extensive deterioration

Montana

Barn/Garage
316 N. 26th Street
Billings Co: Yellowstone MT
Landholding Agency: Interior
Property Number: 619520022
Status: Excess
Reason: Extensive deterioration

North Carolina

Swain Green House
Gashes Creek Rd.
Asheville Co: Buncombe NC 28803–
Landholding Agency: Interior
Property Number: 619640006
Status: Unutilized
Reason: Extensive deterioration

Bldg. SH–7
Marine Corps Base
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy

Property Number: 779410017
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. SH–11
Marine Corps Base
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779410018
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. SH–13
Marine Corps Base
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779410019
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. SH–16
Marine Corps Base
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779410020
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. SH–17
Marine Corps Base
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779410021
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. SH–21
Marine Corps Base
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779410022
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. SH–31
Marine Corps Base
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779410023
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. SSH–10
Marine Corps Base
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779410024
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. AS–209
Marine Corps Base
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779410025
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. AS–589
Marine Corps Base
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779410026
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. AS–590
Marine Corps Base
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779410027
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. AS–4138
Marine Corps Base
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779410028
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. AS–4139
Marine Corps Base
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779410029
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 867
Marine Corps Base
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779410030
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 939
Marine Corps Base
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779410031
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 940
Marine Corps Base
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779410032
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. H–38
Marine Corps Base
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779410033
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. SM–173
Marine Corps Base
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779410034
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 1744
Marine Corps Base
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779410035
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. PT–42
Marine Corps Base
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779420002
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. S–93
Marine Corps Base
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779420003
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. TC–910
Marine Corps Base
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779420004
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. S–942
Marine Corps Base
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779420005
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. S–1213
Marine Corps Base
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779420006
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 79
Marine Corps Air Station
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779420008
Status: Excess
Reason: Secured Area

Bldg. 281
Marine Corps Air Station
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779420009
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 282
Marine Corps Air Station
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 77942001
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 88
Marine Corps Air Station
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779420011
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 98
Marine Corps Air Station
Havelock Co: Craven NC 28533–

Landholding Agency: Navy
Property Number: 779420012
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 99
Marine Corps Air Station
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779420013
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 1234
Marine Corps Air Station
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779420014
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 1235
Marine Corps Air Station
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779420015
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 1246
Marine Corps Air Station
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779420016
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 1390
Marine Corps Air Station
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779420017
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 1710
Marine Corps Air Station
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779420018
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 1742
Marine Corps Air Station
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779420019
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 1743
Marine Corps Air Station
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779420020
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 1744
Marine Corps Air Station
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779420021
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 1745
Marine Corps Air Station
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779420022
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 3450
Marine Corps Air Station
Havelock Co: Craven NC 28533-
Landholding Agency: Navy
Property Number: 779420023
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 8067
Marine Corps Air Station
Havelock Co: Craven NC 28533-
Landholding Agency: Navy
Property Number: 779420024
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 3546
Marine Corps Air Station
Havelock Co: Craven NC 28533-
Landholding Agency: Navy
Property Number: 779420025
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 9017
Piney Island
Marine Corps Air Stations
Cherry Point Co: Carteret NC
Landholding Agency: Navy
Property Number: 779430001
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 9019
Piney Island
Marine Corps Air Stations
Cherry Point Co: Carteret NC
Landholding Agency: Navy
Property Number: 779430002
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 9021
Piney Island
Marine Corps Air Stations
Cherry Point Co: Carteret NC
Landholding Agency: Navy
Property Number: 779430003
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 9023
Piney Island
Marine Corps Air Stations
Cherry Point Co: Carteret NC
Landholding Agency: Navy
Property Number: 779430004
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 9035
Piney Island
Marine Corps Air Stations
Cherry Point Co: Carteret NC
Landholding Agency: Navy
Property Number: 779430005
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Structure #AS582
New River Air Station
Camp Lejeune Co: Onslow NC 28542-0004
Landholding Agency: Navy
Property Number: 779430015
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. AS-299, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542-0004
Landholding Agency: Navy
Property Number: 779430020
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 854, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542-0004
Landholding Agency: Navy
Property Number: 779430021
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 883, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542-0004
Landholding Agency: Navy
Property Number: 779430022
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. TC–174, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542-0004
Landholding Agency: Navy
Property Number: 779430023
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. TC–179 Camp Lejeune
Camp Lejeune Co: Onslow NC 28542-0004
Landholding Agency: Navy
Property Number: 779430024
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 935, Cherry Point
Marine Corps Air Station
Havelock Co: Craven NC 28533-
Landholding Agency: Navy
Property Number: 779430025
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Facility 1972, Cherry Point
Marine Corps Air Station
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779430026
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 3248
Marine Corps Air Station, Cherry Point
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779440009
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. AS 552, Camp Lejeune

Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779440010
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. AS 587, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779440011
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. TT 38, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779440012
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 49, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779440013
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. AS 147, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779440014
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. BB 166, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779440015
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. SM 183, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779440016
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. BB 222, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779440017
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 451, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779440018
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 630, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779440019
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. S 745, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779440020
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 805, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779440021
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. AS 866, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779440022
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 954, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779440023
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 1808, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779440024
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 1810, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779440025
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Structure #SVL 142
Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779510021
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Structure #FC 363
Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779510022
Status: Unutilized
Reason: Secured Area

Structure #AS 583
Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779510023
Status: Unutilized
Reason: Secured Area

Structure #1966
Camp Lejeune
Camp Lejeune Co. Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779510024
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Structure #2322
Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779510025
Status: Unutilized
Reason: Secured Area

Structure RR–85
Camp Lejeune, Base Rifle Range
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property: Unutilized
Reason: Secured Area, Extensive deterioration

Structure SRR–86
Camp Lejeune, Base Rifle Range
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779520017
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 168
Marine Corps Air Station—Cherry Point
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779530015
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 959
Marine Corps Air Station—Cherry Point
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779530016
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 977
Marine Corps Air Station—Cherry Point
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779530017
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 1056
Marine Corps Air Station—Cherry Point
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779530018
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 1739
Marine Corps Air Station—Cherry Point
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779530019
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 1741
Marine Corps Air Station—Cherry Point
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779530020
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 1990
Marine Corps Air Station—Cherry Point
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779530021
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 1991
Marine Corps Air Station—Cherry Point
Havelock Co: Craven NC 28533–

Landholding Agency: Navy
Property Number: 779530022
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 914
Marine Corps Air Station—Cherry Point
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779530023
Status: Excess
Reason: Extensive deterioration

Bldg. 981
Marine Corps Air Station—Cherry Point
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779530024
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 986
Marine Corps Air Station—Cherry Point
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779530025
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 987
Marine Corps Air Station—Cherry Point
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779530026
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 988
Marine Corps Air Station—Cherry Point
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779530027
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 1652
Marine Corps Air Station—Cherry Point
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779530028
Status: Excess
Reason: Other
Comment: Detached Latrine

Bldg. 8525
Marine Corps Air Station—Cherry Point
Co: Jones NC 28585–
Landholding Agency: Navy
Property Number: 779610013
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Structure M171
Marine Corps Base, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779610016
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Structure 910
Marine Corps Base, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779610017
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Structure SVL142
Marine Corps Base, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779610018
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Structure S936
Marine Corps Base, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779610019
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Structure FC363
Marine Corps Base, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779610020
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 924
Marine Corps Base, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779610021
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 970, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779610022
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. SFC–104, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779610023
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. SFC–112, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779610024
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. SA–30, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779610025
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. A–37, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779610026
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 1820, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779610027
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. CR115, Camp Lejeune
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779620001
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Bldg. 080, Camp Lejeune
Greater Sandy Run Training Area
Camp Lejeune Co: Onslow NC 28542–0004
Landholding Agency: Navy
Property Number: 779620023
Status: Unutilized
Reason: Extensive deterioration

Bldg. 1315,
Marine Corps Air Station, Cherry Point
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779620037
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 1748
Marine Corps Air Station, Cherry Point
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779620038
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 1898
Marine Corps Air Station, Cherry Point
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779620039
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 4054
Marine Corps Air Station, Cherry Point
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779620040
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 8075
Marine Corps Air Station, Cherry Point
Havelock Co: Craven NC 28533–
Landholding Agency: Navy
Property Number: 779620041
Status: Excess
Reason: Secured Area, Extensive deterioration

Bldg. 9
VA Medical Center
1100 Tunnel Road
Asheville Co: Buncombe NC 28805–
Landholding Agency: VA
Property Number: 979010008
Status: Underutilized
Reason: Other
Comment: Friable asbestos.

Oregon

Bldg. 0210
500 Nevada Street
Klamath Falls Co: Klamath OR 97601–
Landholding Agency: Interior
Property Number: 619540002
Status: Unutilized
Reason: Extensive deterioration

Bldg. 0211

500 Nevada Street
Klamath Falls Co: Klamath OR 97601–
Landholding Agency: Interior
Property Number: 619540003
Status: Unutilized
Reason: Extensive deterioration

Bldg. 0213
500 Nevada Street
Klamath Falls Co: Klamath OR 97601–
Landholding Agency: Interior
Property Number: 619540004
Status: Unutilized
Reason: Extensive deterioration

Bldg. 0214
500 Nevada Street
Klamath Falls Co: Klamath OR 97601–
Landholding Agency: Interior
Property Number: 619540005
Status: Unutilized
Reason: Extensive deterioration

Bldg. 510
Wilson Dam Residence
Klamath Falls Co: Klamath OR 97601–
Landholding Agency: Interior
Property Number: 619540006
Status: Unutilized
Reason: Extensive deterioration

Pennsylvania

Bldg. 1981
Naval Weapons Station—Q Area
Yorktown Co: York PA 23691–
Landholding Agency: Navy
Property Number: 779640018
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area

Rhode Island

Bldg. 32
Naval Underwater Systems Center
Gould Island Annex
Middletown Co: Newport RI 02840–
Landholding Agency: Navy
Property Number: 779010273
Status: Excess
Reason: Secured Area

Texas

Bldg. 2426
Laguna Shores Housing Area
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010279
Status: Underutilized
Reason: Floodway

Bldg. 2432
Laguna Shores Housing Area
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010280
Status: Underutilized
Reason: Floodway

Bldg. 2476
Laguna Shores Housing Area
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010281
Status: Underutilized
Reason: Floodway

Bldg. 2498
Laguna Shores Housing Area
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010282
Status: Underutilized
Reason: Floodway

Bldg. 2504
Laguna Shores Housing Area
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010283
Status: Underutilized
Reason: Floodway

Bldg. 1730
Laguna Shores Housing Area
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010284
Status: Underutilized
Reason: Floodway

Bldg. 2422
Laguna Shores Housing Area
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010285
Status: Underutilized
Reason: Floodway

Bldg. 2425
Laguna Shores Housing Area
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010286
Status: Underutilized
Reason: Floodway

Bldg. 2430
Laguna Shores Housing Area
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010287
Status: Underutilized
Reason: Floodway

Bldg. 2434
Laguna Shores Housing Area
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010288
Status: Underutilized
Reason: Floodway

Bldg. 2449
Laguna Shores Housing Area
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010289
Status: Underutilized
Reason: Floodway

Bldg. 2450
Laguna Shores Housing Area
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010290
Status: Underutilized
Reason: Floodway

Bldg. 2453
Laguna Shores Housing Area
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010291
Status: Underutilized
Reason: Floodway

Bldg. 2455
Laguna Shores Housing Area
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010292
Status: Underutilized
Reason: Floodway

Bldg. 2456
Laguna Shores Housing Area
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010293
Status: Underutilized
Reason: Floodway

Bldg. 2463
Laguna Shores Housing Area
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010294
Status: Underutilized
Reason: Floodway

Bldg. 2483
Laguna Shores Housing Area
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010295
Status: Underutilized
Reason: Floodway

Bldg. 2516
Laguna Shores Housing Area
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010296
Status: Underutilized
Reason: Floodway

Bldg. 2524
Laguna Shores Housing Area
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010297
Status: Underutilized
Reason: Floodway

Bldg. 2528
Laguna Shores Housing Area
Corpus Christi Co: Nueces TX 78419–
Landholding Agency: Navy
Property Number: 779010298
Status: Underutilized
Reason: Floodway

Bldg. 24
Olin E. Teague Veterans Center
1901 South 1st Street
Temple Co: Bell TX 76504–
Landholding Agency: VA
Property Number: 979010050
Status: Underutilized
Reason: Other
Comment: Friable asbestos.

Bldg. 25
Olin E. Teague Veterans Center
1901 South 1st Street
Temple Co: Bell TX 76504–
Landholding Agency: VA
Property Number: 979010051
Status: Underutilized
Reason: Other
Comment: Friable asbestos.

Bldg. 26
Olin E. Teague Veterans Center
1901 South 1st Street
Temple Co: Bell TX 76504–
Landholding Agency: VA
Property Number: 979010052
Status: Unutilized
Reason: Other
Comment: Friable asbestos.

Virginia

Matthews Property
Rt. 2
Galax Co: Grayson VA 24333–
Landholding Agency: Interior
Property Number: 619640005
Status: Unutilized
Reason: Extensive deterioration

Bldg. 63
Norfolk Naval Shipyard
Portsmouth VA 23709–
Landholding Agency: Navy
Property Number: 779520035
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area

Bldg. 244
Norfolk Naval Shipyard
Portsmouth VA 23709–
Landholding Agency: Navy
Property Number: 779520036
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area

Bldg. 286
Norfolk Naval Shipyard
Portsmouth VA 23709–
Landholding Agency: Navy
Property Number: 779520037
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area

Bldg. 416
Norfolk Naval Shipyard
Portsmouth VA 23709–
Landholding Agency: Navy
Property Number: 779520038
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area

Bldg. 521
Norfolk Naval Shipyard
Portsmouth VA 23709–
Landholding Agency: Navy
Property Number: 779520039
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area

Bldg. 539
Norfolk Naval Shipyard
Portsmouth VA 23709–
Landholding Agency: Navy
Property Number: 779520040
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area

Bldg. 760
Norfolk Naval Shipyard
Portsmouth VA 23709–
Landholding Agency: Navy
Property Number: 779520041
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 763
Norfolk Naval Shipyard
Portsmouth VA 23709–
Landholding Agency: Navy
Property Number: 779520042
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area

Bldg. 1335
Norfolk Naval Shipyard
Portsmouth VA 23709–
Landholding Agency: Navy
Property Number: 779520043
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area

Bldg. 1488
Norfolk Naval Shipyard
Portsmouth VA 23709–
Landholding Agency: Navy
Property Number: 779520044
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area

Bldg. 79
Norfolk Naval Shipyard
Portsmouth VA 23709–5000
Landholding Agency: Navy
Property Number: 779610014
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area

Bldg. 444
Norfolk Naval Shipyard
Portsmouth VA 23709–5000
Landholding Agency: Navy
Property Number: 779620004
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area

Bldg. 459
Norfolk Naval Shipyard
Portsmouth VA 23709–5000
Landholding Agency: Navy
Property Number 779620005
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area

Bldg. 462
Norfolk Naval Shipyard
Portsmouth VA 23709–5000
Landholding Agency: Navy
Property Number 779620006
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area

Bldg. 495
Norfolk Naval Shipyard
Portsmouth VA 23709–5000
Landholding Agency: Navy
Property Number 779620007
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area

Bldg. 761
Norfolk Naval Shipyard
Portsmouth VA 23709–5000
Landholding Agency: Navy
Property Number 779620008
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area

Bldg. 1438
Norfolk Naval Shipyard
Portsmouth VA 23709–5000
Landholding Agency: Navy
Property Number 779620009
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area

Bldg. 1442
Norfolk Naval Shipyard
Portsmouth VA 23709–5000
Landholding Agency: Navy
Property Number 779620010
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area

Bldg. 380B
Naval Weapons Station
Yorktown Co: York VA 23691–
Landholding Agency: Navy
Property Number 779620022
Status: Unutilized
Reason: Secured Area

Bldg. 15A
Norfolk Naval Shipyard
Portsmouth VA 23709–5000
Landholding Agency: Navy
Property Number 779620049
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area

Water Tower
Naval Amphibious Base, Little Creek
Murray Road
Virginia Beach VA
Landholding Agency: Navy
Property Number 779630005
Status: Underutilized
Reason: Floodway

Water Tower
Naval Amphibious Base, Little Creek
Murray Road
Virginia Beach VA
Landholding Agency: Navy
Property Number 779630006
Status: Underutilized
Reason: Floodway

Bldg. LP–20
Naval Air Station Norfolk
Norfolk VA
Landholding Agency: Navy
Property Number 779630021
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material

Bldg. LP–176
Naval Air Station Norfolk
Norfolk VA
Landholding Agency: Navy
Property Number 779630022
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material

Bldg. LP–177
Naval Air Station Norfolk
Norfolk VA
Landholding Agency: Navy
Property Number 779630023
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material

Bldg. 275
Norfolk Naval Shipyard
Portsmouth VA 23709–5000
Landholding Agency: Navy
Property Number 779630024
Status: Unutilized
Reason: Secured Area

Bldg. 430
Norfolk Naval Shipyard
Portsmouth VA 23709–5000
Landholding Agency: Navy
Property Number 779630025
Status: Unutilized
Reason: Secured Area

Bldg. 13
Naval Weapons Station, Yorktown Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630044
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 18
Naval Weapons Station, Yorktown Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630045
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 19
Naval Weapons Station, Yorktown Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630046
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 71
Naval Weapons Station, Yorktown Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630047
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 118
Naval Weapons Station, Yorktown Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630048
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 301
Naval Weapons Station, Yorktown Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630049
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 306
Naval Weapons Station, Yorktown Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630050
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 358
Naval Weapons Station, Yorktown Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630051
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 361
Naval Weapons Station, Yorktown Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630052
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 369
Naval Weapons Station, Yorktown Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630053
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 387
Naval Weapons Station, Yorktown Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630054
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 446
Naval Weapons Station, Yorktown Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630055
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 472
Naval Weapons Station, Yorktown Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630056
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 540
Naval Weapons Station, Yorktown Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630057
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 562
Naval Weapons Station, Yorktown Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630058
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 579
Naval Weapons Station, Yorktown Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630059
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 584
Naval Weapons Station, Yorktown Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630060
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 587
Naval Weapons Station, Yorktown Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630061
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 612
Naval Weapons Station, Yorktown Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630062
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 639
Naval Weapons Station, Yorktown Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630063
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 757
Naval Weapons Station, Yorktown Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630064
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 758
Naval Weapons Station, Yorktown Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630065
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 765
Naval Weapons Station, Yorktown Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630066
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 792
Naval Weapons Station, Yorktown Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630067
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 1245
Naval Weapons Station, Yorktown
Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630068
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 1344
Naval Weapons Station, Yorktown
Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630069
Status: Unutilized

Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 1447
Naval Weapons Station, Yorktown
Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630070
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 1450
Naval Weapons Station, Yorktown
Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630071
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 1452
Naval Weapons Station, Yorktown
Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630072
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 1453
Naval Weapons Station, Yorktown
Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630073
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 1585
Naval Weapons Station, Yorktown
Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630074
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 1904
Naval Weapons Station, Yorktown
Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630075
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Bldg. 1603
Naval Weapons Station, Yorktown
Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779630076
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area, Extensive deterioration

Building 401
Norfolk Naval Shipyard
Portsmouth VA 23709–
Landholding Agency: Navy
Property Number: 779640001
Status: Excess
Reason: Extensive deterioration

Building 235
Norfolk Naval Shipyard
Portsmouth VA 23709–
Landholding Agency: Navy
Property Number: 779640002
Status: Excess
Reason: Within 2000 ft. of flammable or explosive material, Floodway, Secured Area, Extensive deterioration

Building 657
Naval Weapons Station
Yorktown Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779640003
Status: Excess
Reason: Secured Area, Extensive deterioration

Building 380A
Naval Weapons Station
Yorktown Co: York VA 23691–
Landholding Agency: Navy
Property Number: 779640004
Status: Excess
Reason: Secured Area

Bldg. 1980
Naval Weapons Station—Aviation Field
Yorktown Co: York VA 23691-
Landholding Agency: Navy
Property Number: 779640017
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area

Bldg. 55
Naval Base Norfolk, St. Julien's Creek Annex
Co: Chesapeake VA
Landholding Agency: Navy
Property Number: 779710059
Status: Excess
Reason: Extensive deterioration

Bldg. 56
Naval Base Norfolk, St. Julien's Creek Annex
Co: Chesapeake VA
Landholding Agency: Navy
Property Number: 779710060
Status: Excess
Reason: Extensive deterioration

Bldg. 130
Naval Base Norfolk, St. Julien's Creek Annex
Co: Chesapeake VA
Landholding Agency: Navy
Property Number: 779710061
Status: Excess
Reason: Extensive deterioration

Bldg. 240
Naval Base Norfolk, St. Julien's Creek Annex
Co: Chesapeake VA
Landholding Agency: Navy
Property Number: 779710062
Status: Excess
Reason: Extensive deterioration

Washington

Bldg. 57
Naval Supply Center Puget Sound
Manchester Co: Kitsap WA 98353-
Landholding Agency: Navy
Property Number: 779010091
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area

Bldg. 47 (Report 1)
Naval Supply Center, Puget Sound
Manchester Co: Kitsap WA 98353-
Landholding Agency: Navy
Property Number: 779010230
Status: Unutilized
Reason: Secured Area

Bldg. 14
Naval Undersea Warfare Center Div., Keyport
Co: Kitsap WA 98345-7610
Landholding Agency: Navy
Property Number: 779440001
Status: Unutilized
Reason: Secured Area

Bldg. 39
Naval Undersea Warfare Center
Co: Kitsap WA 98345-
Landholding Agency: Navy
Property Number: 779510020
Status: Unutilized
Reason: Secured Area, Extensive deterioration

Wyoming

Bldg. 95
Medical Center
N.W. of town at the end of Fort Road
Sheridan Co: Sheridan WY 82801-
Landholding Agency: VA
Property Number: 979110004
Status: Unutilized
Reason: Other
Comment: Sewage digester for disposal plant.

Bldg. 96
Medical Center
N.W. of town at end of Fort Road
Sheridan Co: Sheridan WY 82801-
Landholding Agency: VA
Property Number: 979110005
Status: Unutilized
Reason: Other
Comment: Pump house for sewage disposal plant.

Structure 99
Medical Center
N.W. of town at the end of Fort Road
Sheridan Co: Sheridan WY 82801-
Landholding Agency: VA
Property Number: 979110006
Status: Unutilized
Reason: Other
Comment: Mechanical screen for sewage disposal plant.

Structure 100
Medical Center
N.W. of town at the end of Fort Road
Sheridan Co: Sheridan WY 82801-
Landholding Agency: VA
Property Number: 979110007
Status: Unutilized
Reason: Other
Comment: Dosing tank for sewage disposal plant.

Structure 101
Medical Center
N.W. of town at the end of Fort Road
Sheridan Co: Sheridan WY 82801–
Landholding Agency: VA
Property Number: 979110008
Status: Unutilized
Reason: Other
Comment: Chlorination chamber for sewage disposal plant.

Bldg. 97, Medical Center
Sheridan Co: Sheridan WY 82801–
Landholding Agency: VA
Property Number: 979410011
Status: Unutilized
Reason: Other
Comment: Sewage disposal plant

Structure 98, Medical Center

Sheridan Co: Sheridan WY 82801–
Landholding Agency: VA
Property Number: 979410012
Status: Unutilized
Reason: Other
Comment: Sludge bed/sewage disposal plant

LAND (by State)

Arizona

Santa Fe Pacific Pipelines
Avenue 7E North from Hwy. 95
Yuma Co: Yuma AZ 85364–
Landholding Agency: Interior
Property Number: 619420003
Status: Unutilized
Reason: Secured Area

Case No. 95–019-Surplus Land
Dale Anderson (Farnsworth)
Mesa Co: Maricopa AZ 85220–
Landholding Agency: Interior
Property Number: 619610001
Status: Excess
Reason: Other
Comment: inaccessible

ARCO Surplus Land
20-foot strip, 53rd Ave.
Phoenix Co: Maricopa AZ 85043–
Landholding Agency: Interior
Property Number: 619620001
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area

58 acres
VA Medical Center
500 Highway 89 North
Prescott Co: Yavapai AZ 86313–
Landholding Agency: VA
Property Number: 970630001
Status: Unutilized
Reason: Floodway

20 acres
VA Medical Center
500 Highway 89 North
Prescott Co: Yavapai AZ 86313–
Landholding Agency: VA
Property Number: 970630002
Status: Underutilized
Reason: Floodway

California

Naval Air Station, Miramar
San Diego Co: San Diego CA 92145–5005
Landholding Agency: Navy
Property Number: 779440026
Status: Underutilized
Reason: Within airport runway clear zone Other
Comment: Inaccessible

Lease Parcel #2
Naval Construction Battalion Center
Port Hueneme Co: Ventura CA 93043–4301
Landholding Agency: Navy
Property Number: 779610004
Status: Underutilized
Reason: Secured Area

N. ½ of Lease Parcel #3
Naval Construction Battalion Center
Port Hueneme Co: Ventura CA 93043–4301
Landholding Agency: Navy
Property Number: 779610005
Status: Underutilized
Reason: Secured Area

Lease Parcel #4
Naval Construction Battalion Center
Port Hueneme Co: Ventura CA 93043–4301
Landholding Agency: Navy
Property Number: 779610006
Status: Underutilized
Reason: Secured Area

Lease Parcel #6
Naval Construction Battalion Center
Port Hueneme Co: Ventura CA 93043–4301
Landholding Agency: Navy
Property Number: 779610007
Status: Underutilized
Reason: Secured Area

Lease Parcel #7
Naval Construction Battalion Center
Port Hueneme Co: Ventura CA 93043–4301
Landholding Agency: Navy
Property Number: 779610008
Status: Underutilized
Reason: Secured Area

Lease Parcel #8
Naval Construction Battalion Center
Port Hueneme Co: Ventura CA 93043–4301
Landholding Agency: Navy
Property Number: 779610009
Status: Underutilized
Reason: Secured Area

Lease Parcel #9
Naval Construction Battalion Center
Port Hueneme Co: Ventura CA 93043–4301
Landholding Agency: Navy
Property Number: 779610010
Status: Underutilized
Reason: Secured Area

Lease Parcel #10
Naval Construction Battalion Center
Port Hueneme Co: Ventura CA 93043–4301
Landholding Agency: Navy
Property Number: 779610011
Status: Underutilized
Reason: Secured Area

Lease Parcel #11
Naval Construction Battalion Center
Port Hueneme Co: Ventura CA 93043–4301
Landholding Agency: Navy
Property Number: 779610012
Status: Underutilized
Reason: Secured Area

DVA Medical Center
4951 Arroyo Road
Livermore Co: Alameda CA 94550-
Landholding Agency: VA
Property Number: 979010023
Status: Unutilized
Reason: Other Comment: 750,000 gallon water reservoir

Florida

Boca Chica Field
Naval Air Station
Key West Co: Monroe FL 23040-
Landholding Agency: Navy
Property Number: 779010097
Status: Unutilized
Reason: Floodway

East Martello Battery #2
Naval Air Station
Key West Co: Monroe FL 33040-
Landholding Agency: Navy
Property Number: 779010275
Status: Excess
Reason: Within airport runway clear zone

Wildlife Sanctuary, VAMC
10,000 Bay Pines Blvd.
Bay Pines Co: Pinellas FL 33504-
Landholding Agency: VA
Property Number: 979230004
Status: Underutilized
Reason: Other
Comment: Inaccessible

Georgia

Naval Submarine Base
Grid G–5 to G–10 to Q–6 to P–2
Kings Bay Co: Camden GA 31547-
Landholding Agency: Navy
Property Number: 779010228
Status: Underutilized
Reason: Secured Area

Idaho

Zamzow Sidewalk Sale
0.5 acres
Boise Co: Ada ID 83705-
Landholding Agency: Interior
Property Number: 619630001
Status: Unutilized
Reason: Within 2000 ft. of flammable or explosive material

Maryland

5,635 sq. ft. of Land
Solomon's Annex
Solomon's MD
Landholding Agency: Navy
Property Number: 779230001
Status: Excess
Reason: Other
Comment: Drainage Ditch

Minnesota

VAMC
VA Medical Center
4801 8th Street No.
St. Cloud Co: Sterns MN 56303-
Landholding Agency: VA
Property Number: 979010049
Status: Underutilized
Reason: Within 2000 ft. of flammable or explosive material

New York

Cooke's Island—32 acres
Lake Champlain
Whitehall Co: Washington NY
Landholding Agency: GSA
Property Number: 549710009
Status: Excess
Reason: Other
Comment: Inaccessible
GSA Number: 1–D–NY–847

Tract 1
VA Medical Center
Bath Co: Steuben NY 14810–
Location: Exit 38 off New York State Route 17.
Landholding Agency: VA
Property Number: 979010011
Status: Unutilized
Reason: Secured Area

Tract 2
VA Medical Center
Bath Co: Steuben NY 14810–
Location: Exit 38 off New York State Route 17.
Landholding Agency: VA
Property Number: 979010012
Status: Unutilized
Reason: Secured Area

Tract 3
VA Medical Center
Bath Co: Steuben NY 14810–
Location: Exit 38 off New York State Route 17.

Landholding Agency: VA
Property Number: 979010012
Status: Underutilized
Reason: Secured Area

Tract 4
VA Medical Center
Bath Co: Steuben NY 14810–
Location: Exit 38 off New York State Route 17.
Landholding Agency: VA
Property Number: 979010014
Status: Unutilized
Reason: Secured Area

Oregon

Cherry Creek Property Disposal
1.56 acres of land
Madras Co: Jefferson OR 97741–
Landholding Agency: Interior
Property Number: 61920008
Status: Unutilized
Reason: Within airport runway clear zone

Portion/Oregon Landfill
3 acres
Ontario Co: Malheur OR 97914–
Landholding Agency: Interior
Property Number: 619630002
Status: Unutilized
Reason: Other
Comment: landlocked

Puerto Rico

119.3 acres
Culebra Island PR 00775–
Landholding Agency: Interior
Property Number: 619210001
Status: Excess
Reason: Floodway

Destino Tract
Eastern Maneuver Area
Vieques PR 00765–
Landholding Agency: Navy
Property Number: 779240016
Status: Excess
Reason: Other
Comment: Inaccessible

Punta Figueras—Naval Station
Ceiba PR 00735–
Landholding Agency: Navy
Property Number: 779240017
Status: Excess
Reson: Floodway

Virginia

50′×50′ site
Naval Air Station Norfolk
SP area
Norfolk VA
Landholding Agency: Navy
Property Number: 779630002
Status: Underutilized
Reason: Within 2000 ft. of flammable or explosive material, Floodway

50′×50′ site
Naval Air Station Norfolk
NM area
Norfolk VA
Landholding Agency: Navy
Property Number: 779630003
Status: Underutilized
Season: Within 2000 ft. of flammable or explosive material

50′×50′ site
Naval Base Norfolk
SDA area
Norfolk VA
Landholding Agency: Navy
Property Number: 779630004
Status: Underutilized
Reason: Within 2000 ft. of flammable or explosive material, Floodway

2—Water Tower Sites
Naval Amphibious Base, Little Creek
D/3rd St.
Virginia Beach VA
Landholding Agency: Navy
Property Number: 779630007
Status: Underutilized
Reason: Floodway

50′×50′ site
Fleet Combat Training Center Atlantic
Loon Court
Virginia Beach VA
Landholding Agency: Navy
Property Number: 779630008
Status: Underutilized
Reason: Within 2000 ft. of flammable or explosive material

50′×50′ site
Fleet Combat Training Center Atlantic
Regulus Avenue
Virginia Beach VA 23461–
Landholding Agency: Navy
Property Number: 779630009
Status: Underutilized
Reason: Within 2000 ft. of flammable or explosive material

50′×50′ site
Naval Weapons Station Yorktown
Barracks/Railroad Rd
Yorktown VA
Landholding Agency: Navy
Property Number: 779630010
Status: Underutilized
Reason: Within 2000 ft. of flammable or explosive material

50′×50′ site
Naval Weapons Station Yorktown
Cheesecake/Burma Rd.
Yorktown VA
Landholding Agency: Navy
Property Number: 779630011
Status: Underutilized
Reason: Within 2000 ft. of flammable or explosive material

50′×50′ site
Naval Weapons Station Yorktown
W. Beachwood/Burma Rd.
Yorktown VA
Landholding Agency: Navy
Property Number: 779630012
Status: Underutilized
Reason: Within 2000 ft. of flammable or explosive material

50′×50′ site
Norfolk Naval Shipyard Portsmouth
Victory Blvd.
Norfolk VA
Landholding Agency: Navy
Property Number: 779630013
Status: Underutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area

Washington

Land (Report 2), 234 acres
Naval Supply Center, Puget Sound
Manchester Co: Kitsap WA 98353–
Landholding Agency: Navy
Property Number: 779010231
Status: Unutilized
Reason: Secured Area

Land-Port Hadlock Detachment
Naval Ordnance Center Pacific Division
Port Hadlock Co: Jefferson WA 98339–
Landholding Agency: Navy
Property Number: 779640019
Status: Underutilized
Reason: Within 2000 ft. of flammable or explosive material, Secured Area

[FR Doc. 97–6135 Filed 3–13–97; 8:45 am]
BILLING CODE 4210–29–M

DEPARTMENT OF THE INTERIOR

Office of the Assistant Secretary—Water and Science; Central Utah Project Completion Act, Upalco Unit Replacement Project

AGENCIES: The Department of the Interior (Department) and the Central Utah Water Conservancy District (District).

ACTION: Notice of the draft environmental impact statement extension of comment period: DES 96–51.

SUMMARY: Pursuant to section 102(2)(C) of the National Environmental Policy Act of 1969, as amended, the Department and the District have issued a joint Draft Environmental Impact Statement (Draft EIS) on the Upalco Unit Replacement Project (Upalco). The Draft EIS was filed with the Environmental Protection Agency on December 27, 1996. Informal requests have been received from Federal agencies to extend the written comment period. Therefore, the date for submittal of written comments is being extended.

DATES: Written comments on the Draft EIS must be submitted or postmarked no later than March 28, 1997.

ADDRESSES: Comments on the Draft EIS should be addressed to: Terry Holzworth, Project Manager, Central Utah Water Conservancy District, 355 West 1300 South, Orem, Utah 84058.

FOR FURTHER INFORMATION CONTACT: Additional copies of the Draft EIS, or copies of the feasibility studies, the resources technical reports, or information on matters related to this notice can be obtained on request from: Ms. Nancy Hardman, Central Utah Water Conservancy District, 355 West 1300 South, Orem, Utah 84058, Telephone: (801) 226–7187, Fax: (801) 226–7150.

Copies are also available for inspection at:

Central Utah Water Conservancy District, 355 West 1300 South, Orem, Utah 84058
Department of the Interior, Natural Resource Library, Serials Branch, 18th

and C Streets, NW, Washington, DC 20240
Department of the Interior, Central Utah Project Completion Act Office, 302 East 1860 South, Provo, Utah 84606
Bureau of Indian Affairs, Uintah and Ouray Agency, 988 South 7500 East, Fort Duchesne, Utah 84026.

Dated: March 10, 1997.

Ronald Johnston,

CUPCA Program Director, Department of the Interior.

[FR Doc. 97–6495 Filed 3–13–97; 8:45 am]

BILLING CODE 4310–RK–P

Office of the Secretary

Notice of Intent (Notice) To Prepare an Environmental Impact Statement (EIS) and Hold Public Scoping Workshops on Water Resource Management Proposals in Churchill, Douglas, Lyon, Storey, and Washoe Counties, Nevada

AGENCY: Office of the Assistant Secretary—Water and Science, Interior.

ACTION: Notice of intent.

SUMMARY: The Department of the Interior plans to hold four public scoping workshops to gather information that can be used to prepare an EIS on actions related to water resources in the Truckee and Carson Rivers. The purpose of this EIS is to review, in a comprehensive manner, four proposed actions and consider the environmental effects of those and other actions. The Truckee-Carson Coordination Office, acting on behalf of the Department of the Interior, will serve as lead agency and supervise preparation of the EIS. Cooperating federal agencies include Bureau of Indian Affairs, Bureau of Reclamation, and U.S. Fish and Wildlife Service.

DATES: Public scoping workshops will be held at the following locations beginning at 7:00 pm and ending no later than 9:00 pm on the dates indicated:

Date	Location
March 11, 1997 ..	Fallon Convention Center, Fallon, Nevada.
March 13, 1997 ..	Fernley Town Building, Fernley, Nevada.
March 18, 1997 ..	U.S. Geological Survey Conference Room, Carson City, Nevada.
March 20, 1997 ..	Washoe County Commissioners Chambers, Reno, Nevada.

Interested persons are encouraged to attend the workshops to identify and discuss major issues, concerns, opportunities, and alternatives that should be considered in the EIS. The workshops will begin with a brief presentation describing the proposed action followed by an opportunity for interested citizens to provide information relevant to the EIS preparation process. The primary purpose of the scoping workshops is to identify issues and information related to the proposed project rather than to debate those issues.

These meetings supplement scoping meetings held in September 1995 on three of the four proposed actions. Scoping comments submitted following those meetings will also be considered in preparing this EIS.

The scoping period will begin on the date of the first scoping meeting and remain open through preparation of the EIS. Interested agencies, organizations, and individuals are asked to submit written comments on the scope of the environmental document on or before April 28, 1997.

ADDRESSES: Interested parties are requested to send their written commnets on the scope of the environmental document, significant issues that should be addressed, and alternatives that should be considered to the following address: EIS Scoping Comments, Truckee-Carson Coordination Office, 1000 William Street, Suite 100, Carson City, Nevada 89701.

SUPPLEMENTARY INFORMATION: The Truckee and Carson Rivers flow eastward out of the Sierra Nevada mountains and drain to interior basins. The Truckee River terminates in Pyramid Lake; the Carson River terminates in the Stillwater wetlands and Carson Sink. Water rights disputes over waters of the Truckee and Carson Rivers date back to the 1860's during a period of booming regional mining and lumbering activity. Consumptive use of water from the two rivers increased significantly during the late 1880's and early 1900's with the advent of various irrigation developments, including the Newlands Irrigation Project, one of the first Federally funded irrigation projects. With the increasing growth and urbanization of the 20th Century, additional demands were placed on the Region's water supply. In addition, issues brought forward by the establishment of the Pyramid Lake Paiute Indian Reservation in 1859, and the Fallon Paiute-Shoshone Tribes Indian Reservation in 1902 played a major role in the evolution of water-rights disputes in the region.

Before the mid-1800's, all water in the Truckee River flowed into Pyramid Lake with overflows forming Winnemucca Lake, supporting fish populations essential to the life and economy of the Pyramid Lake Paiute Tribe. In Lahontan Valley, the Carson River flowed into vast wetlands that sustained major populations of waterfowl, shorebirds and other wildlife. A substantial population of Native Americans inhabited the wetlands and were dependent on its resources. Gradually, upstream consumptive use and changes to water quality in the two rivers contributed to the degradation of wetland and lake habitats and the species that depended on them. Substantial change was caused by the development of the Newlands Irrigation Project, authorized by the Reclamation Act of 1902.

A majority of the Newlands Project acreage, known as the Carson Division, is located in the Carson River watershed. However, in most years, water entitlements in the Carson Division cannot be satisfied solely by Carson River flows. Varying quantities of Truckee River water are annually diverted out of the Truckee River watershed and away from Pyramid Lake to serve agriculture, wetlands, and other water rights in Lahontan Valley and in the Truckee Division of the Newlands Project. Primarily as a result of diversions for the Newlands Project, the level of Pyramid Lake began to decline and today, the lake is more than 65 feet lower than it was 100 years ago. In addition, primary wetlands in Lahontan Valley, which historically fluctuated between 100,000 and 300,000 acres in size, were reduced to a current average of 9,800 acres as a consequence of water use on the Carson River and prolonged drought. Today, remaining wetlands are primarily sustained by irrigation return flows, a portion of which can be of poor quality.

Public Law 101–618, the Truckee-Carson-Pyramid Lake Water Rights Settlement Act, was enacted in 1990. The Act assigned numerous diverse responsibilities to the Department of the Interior for initiating actions addressing, in part, wetlands, endangered species, and water resource management. The Department of the Interior also has responsibilities to satisfy settlement agreements, meet Newlands Project water rights, and properly protect resources held in trust for Indian tribes in the region.

Proposed Actions

The EIS will consider the potential impacts of the proposed water resource management actions described above and the interrelationships of these waters.

1. The Secretary is authorized and directed by Section 206(a) of the Act to acquire water and water rights to sustain, on a long-term average, 25,000 acres of primary wetland habitat in Lahontan Valley. The U.S. Fish and Wildlife Service (FWS) is preparing a wetlands management plan detailing actions necessary to best manage water being acquired to sustain 25,000 acres of wetland habitat, including the timing of water applications to wetlands, and the volumes of acquired water to be applied.

2. Section 207(a) directs the Secretary to expeditiously implement plans for the conservation and recovery of endangered cui-ui, a fish species found only in Pyramid Lake and the lower Truckee River. Section 207(c)(1) authorizes the Secretary to acquire water and water rights to assist the conservation and recovery of the species. General recovery actions are authorized under the Endangered Species Act. The recovery objective stated in the Cui-ui Recovery Plan, completed by the Fish and Wildlife Service in 1992, is to improve the status of cui-ui so that the species has at least a 0.95 probability of persisting for 200 years. This objective necessitates securing spawning habitat in the lower Truckee River and rearing habitat in Pyramid Lake as well as an avenue of passage for spawners and larvae.

3. The Secretary is considering modifications to the Newlands Irrigation Project Operating Criteria and Procedures (OCAP). The OCAP were most recently modified in 1988 and in the intervening years, several factors which affect water management in the Project have changed. For example, the number of water-righted, irrigated acres in the Project has not expanded to meet predicted levels. Also, formulas used to calculate allowable diversions of Truckee River water to the Project need to be revised to reflect current and expected conditions within the Project. Short-term OCAP adjustments within the framework of the existing criteria and procedures are currently in preparation to account for changes in water demand assumptions and operational experience gained since 1988. The Department of the Interior will examine more fundamental potential revisions to OCAP in order to optimize the use of Project water to meet competing uses and legal responsibilities, including serving agricultural water rights, meeting trust responsibilities to the Pyramid Lake Paiute and Fallon Paiute-Shoshone Tribes, conserving and recovering endangered fish species, restoring and protecting Lahontan Valley wetlands, and meeting other water demands.

4. In October 1996, the United States signed the Truckee River Water Quality Settlement Agreement with the cities of Reno and Sparks, Washoe County, the State of Nevada, and the Pyramid Lake Paiute Tribe. The agreement resolves litigation over approval and operation of the Reno-Sparks water treatment facility brought by the Pyramid Lake Paiute Tribe against Reno, Sparks, the State of Nevada, and the U.S. Environmental Protection Agency. Under terms of the agreement, the Department of the Interior will allocate $12 million over five years to acquire Truckee River water rights and dedicate them to a joint program to manage an equal quantity of water rights to be acquired by Reno, Sparks, and Washoe County for the purpose of improving water quality and instream flows in the Truckee River from Reno to Pyramid Lake. In addition, the Department of the Interior agreed to aid Reno, Sparks, and Washoe County in meeting water quality goals by storing acquired water in federal Truckee River reservoirs and timing releases to improve instream flows during normally dry periods of the summer and early fall.

Other Actions To Be Considered

In addition, the EIS will consider an extensive list of proposed and active projects that may have cumulative impacts within the scope of this document. Two actions authorized under P.L. 101–618 are being reviewed in separate EISs. These are: (1) Modification of reservoir and river operations on the Truckee River as described in the Truckee River Operating Agreement draft EIS currently being prepared by the Bureau of Reclamation and the U.S. Fish and Wildlife Service (FWS), and expected to be released in the spring of 1997; and (2) acquisition of water for development of wetlands at the terminus of the Carson River as described in the Lahontan Valley Wetlands Water Rights Acquisition Program final EIS released by the FWS in September 1996.

Additional projects and actions to be considered include the new Operation and Maintenance contract for the Newlands Irrigation Project; possible agreement between the Department of the Interior and the Fallon Paiute-Shoshone Tribe regarding water and water-rights management, acquisition, and protection; efforts of the Fish and Wildlife Service to acquire water from the Upper Carson River; implementation of the agreement with the Department of the Navy to conserve and transfer water from the Fallon Naval Air Station to the Fish and Wildlife Service; and possible water storage agreements for Lahontan Reservoir. The EIS proposed in this Notice will, as part of its analysis, consolidate and review the effects of these and other water management actions identified during the scoping process.

This notice is being published, and the environmental review of this project will be completed, in accordance with Council on Environmental Quality Regulations for Implementing the National Environmental Policy Act (40 CFR 1508.22).

Tentative Schedule

Estimated dates for completion of activities for an environmental impact statement evaluating the potential impacts of water resources management in the Truckee and Carson Rivers program are:

Milestone	Date
Public Scoping Period	April 1997.
Identification of Alternatives.	May 1997.
Draft EIS Published ..	December 1997.
Public Hearings on DEIS.	January 1998.
Final EIS filed with EPA.	June 1998.
Implementation of Decisions.	August 1998.

Dated: March 7, 1997.

Patricia J. Beneke,

Assistant Secretary—Water and Science.

[FR Doc. 97–6471 Filed 3–13–97; 8:45 am]

BILLING CODE 4310–RK–M

Exxon Valdez Oil Spill Trustee Council; Restoration of Resources and Services Injured by Oil Spill; (FY 1998) Proposals Request

AGENCY: Department of the Interior, Office of the Secretary.

ACTION: Invitation for proposals.

SUMMARY: The Exxon Valdez Oil Spill Trustee Council is asking the public, private organizations, and government agencies to submit proposals for the restoration of the Exxon Valdez oil spill region. The Invitations to Submit Restoration Proposals for Federal Fiscal Year 1998, a booklet explaining the process, is available from the Trustee Council office.

DATES: Proposals are due April 15, 1997, at 5:00 p.m.

ADDRESSES: Exxon Valdez Oil Spill Trustee Council, 645 ‘‘G’’ Street, Suite 401, Anchorage, Alaska 99501.

FOR FURTHER INFORMATION CONTACT: The Restoration Office, (907) 278–8012 or toll free at (800) 478–7745 (in Alaska) or (800) 283–7745 (outside Alaska).

SUPPLEMENTARY INFORMATION: Following the Exxon Valdez oil spill in March 1989, a Trustee Council of three state and three federal trustees, including the Secretary of the Interior, was formed. The Trustee Council prepared a restoration plan for the injured resources and services within the oil spill area. The restoration plan calls for annual work plans identifying projects to accomplish restoration. Each year proposals for restoration projects are solicited from a variety of organizations, including the public.

Dated: March 7, 1997.

Willie R. Taylor,

Director, Office of Environmental Policy and Compliance.

[FR Doc. 97–6530 Filed 3–13–97; 8:45 am]

BILLING CODE 4310–RG–P

Fish and Wildlife Service

Preparation of an Environmental Impact Statement on a Permit Application to Incidentally Take Threatened and Endangered Species in Association With the San Joaquin County Multiple Species Conservation Plan in San Joaquin County, CA

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Notice of intent.

SUMMARY: This notice advises the public that the U.S. Fish and Wildlife Service (Service) and the County of San Joaquin, California, intend to prepare a joint Federal Environmental Impact Statement/State Environmental Impact Report (Statement/Report), pursuant to the National Environmental Policy Act and California Environmental Quality Act. The Service intends to proceed with preparation of the joint Statement/Report in response to an anticipated application by San Joaquin County to obtain a 30-year permit under the Federal Endangered Species Act that would authorize incidental take of up to approximately 100 species of plants and animals. The anticipated application would be accompanied by a Habitat Conservation Plan. This notice describes the proposed action and alternatives, and the history of the scoping process.

DATES: Written comments will be accepted by the Service at the address below until April 14, 1997.

ADDRESSES: Information and comments related to preparation of the joint Statement/Report should be submitted to Mr. Wayne White, Field Supervisor, U.S. Fish and Wildlife Service, 3310 El Camino Avenue, Suite 120, Sacramento, California 95821. Written comments also may be sent by facsimile to (916) 979–2723.

FOR FURTHER INFORMATION CONTACT: Mr. Peter Cross, Division of Endangered Species, at the above Sacramento address, telephone (916) 979–2725.

SUPPLEMENTARY INFORMATION:

Availability of Documents

Background material will be available for public inspection, by appointment, during normal business hours (7:30 a.m. to 4:30 p.m., Monday through Friday) at the above Service address.

History of the Scoping Process

The public scoping process for the Statement/Report was formally initiated with the publication by San Joaquin County of a Notice of Public Hearing Scoping Meetings and Notice of Preparation/Notice of Intent for the Preparation of a Joint Environmental Impact Report/Environmental Impact Statement for the San Joaquin County Multi-species Habitat Conservation and Open Space Plan in *The Record* (the largest distribution newspaper in San Joaquin County) on January 22, 1997. This Notice also was sent to 271 organizations, agencies, native American tribes and other interested public within San Joaquin County and adjacent cities and counties. On February 6, 1997, the Service attended a public scoping meeting held in the city of Stockton, California, pursuant to the January 22 notice. During this meeting, concern was raised regarding the potential impact of linear projects that could create significant dispersal barriers to certain species that will be addressed in the Habitat Conservation Plan (e.g., water delivery canals). The Service intends to use the information collected at the February 6 scoping meeting and a second scoping meeting held on March 5, 1997, in Lodi, California, as well as other information and comments received in development of the joint Statement/Report.

Proposed Action

San Joaquin County intends to submit an application to the Service for a 30-year incidental take permit under Section 10(a)(1)(B) of the Federal Endangered Species Act of 1973, as amended (Act). The application would include a Multi-Species Habitat Conservation and Open Space Plan (Plan) that would serve as a Habitat Conservation Plan as defined by Section 10(a)(1)(B) of the Act.

The Service anticipates that San Joaquin County would seek a permit authorizing incidental take, now or in the future, of up to approximately 100 species, to the extent that take is prohibited under Section 9 of the Act for each of these species. The anticipated permit application would include 12 listed species: the endangered San Joaquin kit fox (*Vulpes macrotis mutica*), Conservancy fairy shrimp (*Branchinecta conservatio*), longhorn fairy shrimp (*Branchinecta longiantenna*), vernal pool tadpole shrimp (*Lepidurus packardi*), large-flowered fiddleneck (*Amsinckia grandiflora*), and palmate-bracted bird's-beak (*Cordylanthus palmatus*), and the threatened California red-legged frog (*Rana aurora draytonii*), valley elderberry longhorn beetle (*Desmocerus californicus dimorphus*), vernal pool fairy shrimp (*Branchinecta lynchi*), delta smelt (*Hypomesus transpacificus*), giant garter snake (*Thamnophis gigas*), and Aleutian Canada goose (*Branta canadensis leucopareia*). In addition, the anticipated application likely would seek assurances for future incidental take, should it become necessary, of 83 currently unlisted species. These unlisted species include 4 species proposed for listing: the Sacramento splittail (*Pogonichthys macrolepidotus*), succulent owl's clover (fleshy owl's clover) (*Castilleja campestris ssp. succulenta*) and Colusa grass (*Neostapfia colusana*), currently proposed for threatened status, and Greene's tuctoria (*Tuctoria greenei*), currently proposed for endangered status. Should an unlisted species covered by the Plan be listed in the future, take authorization would become effective upon listing under the Act.

The anticipated Plan would encompass all of San Joaquin County: approximately 1,400 square miles (900,000 acres), including 43 percent of the Sacramento-San Joaquin Delta. The Plan, however, would only be applicable to the area covered by those jurisdictions choosing to adopt the Plan. The anticipated Plan would allow conversion of up to 104,299 acres of land to non-open space uses while providing compensation for approximately 100 plant and animal species and 52 vegetative communities, including the conversion of vernal pools to such uses pursuant to the Federal Clean Water Act.

The anticipated Plan would have multiple purposes, all of which address the conversion of open space (for wildlife, agricultural, recreational, educational, flood control and other uses) to non-open space uses. The anticipated Plan would allow new development to proceed with predetermined, standardized mitigation measures for habitat loss. The anticipated Plan would eliminate the need for project surveys and mitigation negotiations, and would be limited to payment of a fee (or in-lieu land dedications, if preferred) and implementation of incidental take avoidance measures.

The anticipated Plan would be completed by the San Joaquin Council of Governments (Council of Governments) through a planning process pursuant to a Memorandum of Understanding adopted by the Service, San Joaquin Council of Governments, San Joaquin County, the California Department of Fish and Game, Caltrans, and the cities of Escalon, Lathrop, Lodi, Manteca, Ripon, Stockton, and Tracy.

Only those agencies adopting the Plan would be covered by it. Agencies indicating interest in adopting the anticipated Plan are: the San Joaquin Council of Governments; San Joaquin County; Caltrans; Federal Highway Administration; San Joaquin Area Flood Control Agency; Stockton East Water District; Reclamation Districts, some local School Districts; East Bay Municipal Utilities District; and the cities of Escalon, Lathrop, Lodi, Manteca, Ripon, Stockton, and Tracy. To receive coverage under the Plan, incidental take authorizations would be required by each of these entities from the Service and California Department of Fish and Game.

The Plan would be voluntary for individual project proponents. This means that if the anticipated Plan is prepared and approved and its associated incidental take permit issued, individuals would have the option of either participating in the Plan or negotiating directly with the State and Federal permitting agencies. Specifically, for local jurisdictions adopting the Plan, the following alternatives would be available to individuals undertaking activities covered by the Plan within that jurisdiction unless exempted by the Plan: (1) Pay the appropriate fee; (2) dedicate, as conservation easements or fee title, habitat lands; or (3) perform/undertake alternative mitigation as approved by the permittee. Such alternative mitigation would be equivalent to, or otherwise consistent with, the purposes of the anticipated Plan.

Alternatives

To date, the following alternatives have been considered during the planning process:

Full Plan Alternative/Proposed Project: The anticipated Plan would include coverage for approximately 100 special status species and 52 vegetative communities occurring in the County, including wetlands, specifically vernal pools.

No Plan Alternative: This alternative would maintain the current process of negotiating mitigation and obtaining incidental take permits for impacts to wildlife habitat on a project-by-project basis.

Moderate Plan Alternative A: This alternative would exclude species not currently listed under the State and Federal Endangered Species Acts (i.e., non-listed species of special concern) and would exclude wetland mitigation under the anticipated Plan.

Moderate Plan Alternative B: This alternative would address Plan funding if some jurisdictions do not participate in the Plan and if a five-acre exemption is adopted during reauthorization of the Federal Endangered Species Act.

Economic Alternatives: This alternative would involve a single fee versus the tiered fee provided for in the Proposed Project.

Mitigation Alternatives: This would involve a one-half to one compensation level with increased preserve enhancements for agricultural habitat lands versus the one-to-one compensation with lesser preserve enhancements provided for in the Proposed Project.

The comment period will provide an opportunity to address the potential effects of these alternatives and to propose others. Interested persons are encouraged to comment on the issues and alternatives to be addressed in the joint Statement/Report.

Environmental review of the joint Statement/Report will be in accordance with the requirements of the National Environmental Policy Act of 1969, as amended (42 U.S.C. 4321 *et seq.*), National Environmental Policy Act regulations (40 CFR parts 1500–1508), other appropriate regulations, and Service procedures for compliance with those regulations. The notice is being furnished in accordance with section 1501.7 of the National Environmental Policy Act to obtain suggestions and information from other agencies and the public on the scope of issues to be addressed in the joint Statement/Report.

Dated: March 7, 1997.

Thomas J. Dwyer,

Regional Director, Region 1, Portland, Oregon.

[FR Doc. 97–6494 Filed 3–13–97; 8:45 am]

BILLING CODE 4310–55–P

Bureau of Land Management

[MT–962–1430–00-CCAM]

Notice of Availability for the Proposed Cooke City Area Mineral Withdrawal Draft Environmental Impact Statement

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice of availability.

SUMMARY: This notice of availability is issued by the Bureau of Land Management, Interior, with the Forest Service, Agriculture, as the joint lead agency. The draft Environmental Impact Statement (EIS) documents the effects of withdrawing from federal mineral location and entry up to 22,000 acres of federal mineral estate near Cooke City, Montana. The proposed mineral withdrawal would also apply to hardrock minerals acquired by the United States and managed as leasable minerals. The proposed mineral withdrawal would be subject to review after 20 years.

FOR FURTHER INFORMATION CONTACT: John Thompson, BLM Co-Lead, or Larry Timchak, FS Co-Lead, CCAM, P.O. Box 36800, Billings, MT 59107–6800. Phone (406) 255–0322.

SUPPLEMENTARY INFORMATION: This EIS analyzes the environmental consequences of two alternatives. The proposed withdrawal of federal locatable minerals would not allow new mining claims to be filed on federal lands. Unpatented mining claims with valid existing rights and private lands would not be affected. The no action alternative (No Mineral Withdrawal) provides a baseline for comparison. This alternative would continue the management that existed prior to September 1, 1995.

DATES: Public informational meetings (open houses) will be held April 1, 1997, in Cooke City, Montana, at the Fire Hall; April 3, 1997, in Livingston, Montana, at the Best Western Yellowstone Inn; April 9, 1997, in Cody, Wyoming, at the Cody Club Room; and April 10, 1997, in Red Lodge, Montana, at the LuPine Inn. Officials from the BLM and FS will be present at these open houses from 4:00 p.m. until 8:00 p.m. each day.

Dated: February 27, 1997.

Daniel T. Mates,

Acting Deputy State Director, Division of Resources.

[FR Doc. 97–5401 Filed 3–13–97; 8:45 am]

BILLING CODE 4310–DN–P

[OR–050–1020–00: GP–0121]

Notice of Meeting of Resource Advisory Council and Provincial Advisory Committee Rangeland Standards Indicator Subgroup

AGENCY: Bureau of Land Management, Interior.

ACTION: Meeting of rangeland standards indicator subgroup: The Dalles, Oregon; April 9–10, 1997.

SUMMARY: Draft rangeland standards and guidelines for livestock grazing on public land in Oregon and Washington, managed by the Bureau of Land Management (BLM), have been developed in consultation with three Resource Advisory Councils (Eastern Washington, John Day-Snake and Southeast Oregon RAC's) and three Provincial Advisory Committees (Deschutes, Klamath and Southwest Oregon PAC's). The RAC's and PAC's have chartered a subgroup of scientists, other federal state agency personnel, Tribal and interest Group representatives to review draft rangeland health indicators developed in connection with the draft standards and guidelines. The subgroup will meet to review these draft indicators on April 9 and 10, 1997, at the Columbia Gorge Community College Auditorium, 400 Scenic Drive, The Dalles, Oregon. The meeting will begin at 10 a.m. on April 9, 1997, and is open to the public. A report of the indicator subgroup will be given to each RAC and PAC and used to assist the RAC's and PAC's in making recommendations to the BLM on the final standards and guidelines later in 1997.

FOR FURTHER INFORMATION CONTACT: Hugh Barrett, Bureau of Land Management, Oregon State Office, 1515 SW 5th Ave., Portland, Oregon 97208, or call 503–952–6051.

Dated: March 7, 1997.

James L. Hancock,

Prineville District Manager.

[FR Doc. 97–6435 Filed 3–13–97; 8:45 am]

BILLING CODE 4310–33–M

[CA–017–4210–03; CACA 30669]

Notice of Realty Action; Recreation and Public Purposes (R&PP) Act Classification; Proposed Issuance of R&PP Lease; California

AGENCY: Bureau of Land Management.

ACTION: Notice.

SUMMARY: The following public lands in Mono County, California have been examined and found suitable for classification for lease to the County of Mono, State of California under the provisions of the Recreation and Public Purposes Act, as amended (43 U.S.C. 869 *et seq.*). The County of Mono proposes to use the lands for a Public Gun Range facility.

Mount Diablo Meridian

T. 5 N., R. 25 E.,
Sec. 10, S½S½NW¼NW¼NW¼, SW¼NW¼NW¼, W½SW¼NW¼, S½S½SE¼SW¼NW¼, N½NW¼NW¼SW¼, NE¼NW¼SW¼ excepting therefrom those public lands south of WSA CA–010–102 boundary shown on the Bureau of Land Management Master Title Plats.

Containing 47 acres more or less.

The lands are not needed for Federal purposes. The lease is consistent with current BLM land use planning and would be in the public interest. The decision to lease is based on the Finding of No Significant Impact and Decision Record signed March 4, 1997 for Environmental Assessment CA–017–97–21. The Decision Record found Alternative 2 the Modified Proposed Action with mitigation as the acceptable alternative.

The lease, when issued, will be subject to the following terms, conditions and reservations:

1. Provisions of the Recreation and Public purposes Act and to all applicable regulations of the Secretary of the Interior.
2. A right-of-way for ditches and canals constructed by the authority of the United States.
3. All minerals shall be reserved to the United States, together with the right to prospect for, mine, and remove the minerals.
4. A right-of-way for streets, roads, and utilities in accordance with the transportation plan for Mono County.
5. A utility line right-of-way CAS 059135 with width of 15 feet from centerline.

Detailed information concerning this action is available for review at the office of the Bureau of Land Management, Bishop Resource Area Office, 785 North Main St. Suite E, Bishop, California, 93514.

Upon publication of this notice in the Federal Register, the lands will be segregated from all other forms of appropriation under the public land laws, including the general mining laws, except for lease under the Recreation and Public Purposes Act and leasing under the mineral leasing laws. For a period of 45 days from the date of publication of this notice in the Federal Register, interested persons may submit comments regarding the proposed lease or classification of the lands to the District Manager, Bureau of Land Management Bakersfield District Office, 3801 Pegasus Drive Bakersfield, California, 93308.

CLASSIFICATION COMMENTS: Interested parties may submit comments involving the suitability of the land for a public gun range facility. Comments on the classification are restricted to whether the land is physically suited for the proposal, whether the use will maximize the future use or uses of the land, whether the use is consistent with local planning and zoning, or if the use is consistent with State and Federal programs.

APPLICATION COMMENTS: Interested parties may submit comments regarding the specific use proposed in the lease application and plan of development, whether the BLM followed proper administrative procedures in reaching the decision, or any other factor not directly related to the suitability of the land for a public gun range facility.

Any adverse comments will be reviewed by the State Director. In the absence of any adverse comments, the classification will become effective 60 days from the date of publication of this notice in the Federal Register.

Dated: March 4, 1997.

Genivieve D. Rasmussen,

Area Manager, Bishop Resource Area.

[FR Doc. 97–6450 Filed 3–13–97; 8:45 am]

BILLING CODE 4310–40–P

[WY–989–1050–00–P]

Filing of Plats of Survey; Wyoming

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice.

SUMMARY: The plats of survey of the following described lands are scheduled to be officially filed in the Wyoming State Office, Cheyenne, Wyoming, thirty (30) calendar days from the date of this publication.

Sixth Principal Meridian, Wyoming

T.43 N., R. 72 W., accepted March 3, 1997
T.42 N., R. 73 W., accepted March 3, 1997
T.43 N., R. 73 W., accepted March 3, 1997
T.44 N., R. 73 W., accepted March 3, 1997
T.45 N., R. 73 W., accepted March 3, 1997
T.43 N., R. 74 W., accepted March 3, 1997
T.44 N., R. 74 W., accepted March 3, 1997

If protests against a survey, as shown on any of the above plats, are received prior to the official filing, the filing will be stayed pending consideration of the protest(s) and or appeal(s). A plat will not be officially filed until after disposition of protest(s) and or appeal(s).

These plats will be placed in the open files of the Wyoming State Office, Bureau of Land Management, 5353 Yellowstone Road, Cheyenne, Wyoming, and will be available to the public as a matter of information only. Copies of the plats will be made available upon request and repayment of the reproduction fee of $1.10 per copy.

A person or party who wishes to protest a survey must file with the State Director, Bureau of Land Management, Cheyenne, Wyoming, a notice of protest prior to thirty (30) calendar days from the date of this publication. If the protest notice did not include a statement of reasons for the protest, the protestant shall file such a statement with the State Director within thirty (30) calendar days after the notice of protest was filed.

The above-listed plats represent dependent resurveys, subdivision of sections.

FOR FURTHER INFORMATION CONTACT: Bureau of Land Management, P.O. Box 1828, 5353 Yellowstone Road, Cheyenne, Wyoming 82003.

Dated: March 4, 1997.

John P. Lee,

Chief, Cadastral Survey Group.

[FR Doc. 97–6415 Filed 3–13–97; 8:45 am]

BILLING CODE 4310–22–M

DEPARTMENT OF JUSTICE

Drug Enforcement Administration

Agency Information Collection Activities: New Collection; Comment Request

ACTION: Notice of information collection under review; Collection of laboratory analysis data on drug samples tested by non-Federal (state and local government) crime laboratories.

The proposed information collection is published to obtain comments from the public and affected agencies. Comments are encouraged and will be accepted until May 13, 1997.

We are requesting written comments and suggestions from the public and affected agencies concerning the proposed collection of information. Your comments should address one or more of the following four points:

1. 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;
2. Evaluate the accuracy of the agencies estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;
3. Enhance the quality, utility, and clarity of the information to be collected; and
4. 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 submission of responses.

Comments and/or suggestions regarding the item(s) contained in this notice, especially regarding the estimated public burden and associated response time should be directed to Mr. Frank L. Sapienza, Chief, Drug and Chemical Evaluation Section, Office of Diversion Control, Drug Enforcement Administration, Washington, D.C. 20537. Telephone: (202) 307–7183; or Fax: (202) 307–8570. If you have additional comments, suggestions, or need a copy of the proposed information collection instrument with instructions, or additional information, please contact Mr. Frank L. Sapienza.

Additionally, comments may also be submitted to the Department of Justice (DOJ), Justice Management Division, Information Management and Security Staff, Attention: Department Clearance Officer, Suite 850, Washington Center, 1001 G Street, NW, Washington, DC 20530. Additional comments may be submitted to DOJ via facsimile at 202–514–1590.

Overview of this information collection:

1. *Type of Information Collection:* New Collection.
2. *Title of the Form/Collection:* Collection of analyzed drug data from non-Federal forensic crime laboratories.
3. *Agency form number:* None; *Applicable component of the Department of Justice sponsoring the collection:* Office of Diversion Control, Drug Enforcement Administration, Department of Justice.
4. *Affected public who will be asked to respond, as well as a brief abstract: Primary:* State and local crime laboratories. *Other:* None.

DEA is required under the Controlled Substances Act (CSA) [21 U.S.C. 811 (b)] to gather data relevant to a determination of the actual or relative abuse potential of drugs. Existing Federal drug abuse data bases do not provide the type or quality of information necessary to accomplish this task in a timely and efficient manner. Non-Federal crime laboratories conduct chemical analyses on a significantly larger number of illicit drug samples than DEA's seven laboratories. The non-Federal analyzed drug data is an untapped resource which would give DEA a very comprehensive representation of drug trafficking in the U.S. This data has the highest degree of validity because it is verified by chemical analysis. DEA is coordination this voluntary, cooperative program to provide a centralized source of analyzed laboratory drug data. Participating laboratories and other government agencies will be permitted to access part of the data base.

5. An estimate of the total number of respondents and the amount of time estimated for an average respondent to respond: 330 respondents at 12 times per year at 8 hours per response.

6. An estimate of the total public burden (in hours) associated with the collection: 31,680 annual burden hours.

Public comment on this proposed information collection is strongly encouraged.

Dated: March 11, 1997.

Robert B. Briggs,

Department Clearance Officer, United States Department of Justice.

[FR Doc. 97–6514 Filed 3–13–97; 8:45 am]

BILLING CODE 4410–09–M

FEDERAL MINE SAFETY AND HEALTH REVIEW COMMISSION

Sunshine Act Meeting; March 11, 1997

TIME AND DATE: 11:45 a.m., Tuesday, March 4, 1996.

PLACE: Room 6005, 6th Floor, 1730 K Street, N.W., Washington, D.C.

STATUS: Closed [Pursuant to 5 U.S.C. § 552b(c)(10)].

MATTERS TO BE CONSIDERED: It was determined by a unanimous vote of the Commissioners that the Commission consider and act upon the following in closed session:

McClanahan v. *Wellmore Coal Corp*, Docket No. VA 95–9–D.

No earlier announcement of the scheduling of this meeting was possible.

CONTACT PERSON FOR MORE INFO: Jean Ellen (202) 653–5629/(202) 708–9300 for TDD Relay/1–800–877–8339 for toll free.

Jean H. Ellen,

Chief Docket Clerk.

[FR Doc. 97–6711 Filed 3–12–97; 3:44pm]

BILLING CODE 6735–01–M

NATIONAL SCIENCE FOUNDATION

Proposed Collection: Comment Request

Title of Proposed Collection: Request for Proposals (RFP).

In compliance with the requirement of Section 3506(c)(2)(A) of the Paperwork Reduction Act of 1995 for opportunity for public comment on proposed data collection projects, the National Science Foundation (NSF) will publish periodic summaries of proposed projects. This material is being submitted for OMB review with no changes. To request more information on the proposed project or to obtain a copy of the data collection plans and instruments, call the NSF Clearance Officer on (703) 306–1125 x2010.

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 of the proposed collection of information; (c) ways to enhance the quality, utility, and clarity of the information on respondents, including through the use of automated collection techniques or other forms of information technology.

Proposed Project: The Federal Acquisition Regulations (FAR) Subpart 15.4—''Solicitation and Receipt of Proposals'' prescribes policies and procedures for preparing and issuing Requests for Proposals. The FAR System has been developed in accordance with the requirement of the Office of Federal Procurement Policy Act of 1974, as amended. The NSF Act of 1950, as amended, 42 U.S.C. 1870, Sec. II, states that NSF has the authority to:

(c) Enter into contracts or other arrangements, or modifications thereof, for the carrying on, by organizations or individuals in the United States and foreign countries, including other government agencies of the United States and of foreign countries, of such scientific or engineering activities as the Foundation deems necessary to carry out the purposes of this Act, and, at the request of the Secretary of Defense, specific scientific or engineering activities in connection with matters relating to international cooperation or national security, and, when deemed appropriate by the Foundation, such contracts or other arrangements or modifications thereof, may be entered into without legal consideration, without performance or other bonds and without regard to section 5 of title 41, U.S.C.

Use of the Information: Request for Proposals (RFP) is used to competitively solicit proposals in response to NSF need for services. Impact will be on those individuals or organizations who elect to submit proposals in response to the RFP. Information gathered will be evaluated in light of NSF procurement requirements to determine who will be awarded a contract.

Burden on the public: The Foundation estimates that approximately 120 hours may be required in the process for submitting a proposal.

Send comments to Gail A. McHenry, Reports Clearance Officer, National Science Foundation, 4201 Wilson Boulevard, Suite 245, Arlington, Virginia 22230. Written comments should be received within 60 days of the date of this notice.

Dated: March 10, 1997.

Gail A. McHenry,

Reports Clearance Officer.

[FR Doc. 97–6521 Filed 3–13–97; 8:45 am]

BILLING CODE 7555–01–M

Special Emphasis Panel for Geosciences; Notice of Meeting

In accordance with the Federal Advisory Committee Act (Pub. L. 92–463, as amended), the National Science Foundation announces the following meeting:

Name: Special Emphasis Panel for Geosciences (1756).
Date: April 2–4, 1997.
Time: 7:30 a.m. to 9:00 p.m. each day.
Place: Room 340 & 380, National Science Foundation, 4201 Wilson Boulevard, Arlington, VA 22230.
Type of meeting: Closed.
Contact person: Dr. Maryellen Cameron, Program Director, Petrology and Geochemistry Program, Division of Earth Sciences, Room 785, National Science Foundation, Arlington, VA 22230, (703) 306–1554.
Purpose of meeting: To provide advice and recommendations concerning proposals submitted to NSF for financial support.
Agenda: To review and evaluate environmental geochemistry and biogeochemistry proposals as part of the selection process for awards.
Reason for closing: The proposals being reviewed include information of a proprietary or confidential nature, including technical information; financial data, such as salaries; and personal information concerning individuals associated with proposals. These matters are exempt under 5 U.S.C. 552b(c), (4) and (6) of the Government in the Sunshine Act.

Dated: March 10, 1997.

Linda Allen-Benton,

Deputy Director, Division of Human Resource Management, Acting Committee Management Officer.

[FR Doc. 97–6453 Filed 3–13–97; 8:45 am]

BILLING CODE 7555–01–M

Special Emphasis Panel in Geosciences; Notice of Meeting

In accordance with the Federal Advisory Committee Act (Pub L. 92–463, as amended), the National Science Foundation announces the following meeting:

Name: Special Emphasis Panel in the Geosciences (1756).
Date and time: April 1–2, 1997, 8:30 A.M.–5:00 P.M.
Place: National Center for Atmospheric Research (NCAR), 1850 Table Mesa Drive, Boulder, CO 80303 and the University Corporation for Atmospheric Research (UCAR), 3300 Mitchell Lane, Boulder, CO 80301.
Type of meeting: Closed.
Contact person: Dr. Clifford Jacobs, Section Head for the UCAR and Lower Atmospheric Facility Oversight Section, Division of Atmospheric Sciences, Room 775, National Science Foundation, 4201 Wilson Blvd., Arlington, VA 22230. Telephone number is (703) 306–1521.
Purpose of meeting: Site visit and review of UCAR/NCAR Advanced Studies Program.
Agenda: To review and evaluate UCAR/NCAR Advanced Studied Program.
Reason for closing: The materials being reviewed include information of a proprietary or confidential nature, including technical information; financial data; and personal information concerning individuals associated with the proposals. These matters are exempted under 5 U.S.C. 552b(c), (4) and (6) of the Government Sunshine Act.

Dated: March 10, 1997.

Linda Allen-Benton,

Deputy Director, Division of Human Resource Management, Acting Committee Management Officer.

[FR Doc. 97–6454 Filed 3–13–97; 8:45 am]

BILLING CODE 7555–01–M

Special Emphasis Panel in Geosciences; Notice of Meeting

In accordance with the Federal Advisory Committee Act (Pub. L. 92–463, as amended), the National Science Foundation announces the following meeting:

Name: Special Emphasis Panel in the Geosciences (1756).
Date and time: March 31–April 4, 1997, 8:30 a.m.–5:00 p.m.
Place: National Center for Atmospheric Research (NCAR), 1850 Table Mesa Drive, Boulder, CO 80303 and the University Corporation for Atmospheric Research (UCAR), 330 Mitchell Lane, Boulder, CO 80301.
Type of meeting: Closed.
Contact person: Dr. Clifford Jacobs, Section Head for the UCAR and Lower Atmospheric Facility Oversight Section, Division of Atmospheric Sciences, Room 775, National Science Foundation, 4201 Wilson Blvd., Arlington, VA 22230. Telephone number is (703) 306–1521.

Purpose of meeting: Site visit and review of UCAR/NCAR.

Agenda: to review and evaluate UCAR management of NCAR.

Reason for closing: The materials being reviewed include information of a proprietary or confidential nature, including technical information; financial data; and personal information concerning individuals associated with the proposals. These matters are exempted under 5 U.S.C. 552b(c), (4) and (6) of the Government in the Sunshine Act.

Dated: March 10, 1997.

Linda Allen-Benton,

Deputy Director, Division of Human Resource Management, Acting Committee Management Officer.

[FR Doc. 97–6455 Filed 3–13–97; 8:45 am]

BILLING CODE 7555–01–M

Special Emphasis Panel in Mathematical Sciences; Notice of Meeting

In accordance with the Federal Advisory Committee Act (Pub. L. 92–463, as amended), the National Science Foundation announces the following meeting.

Name and committee code: Special Emphasis in Mathematical Sciences (1204).

Date and time: April 3–5, 1997; 8:30 a.m. until 5:00 p.m.

Place: Room 1020, National Science Foundation, 4201 Wilson Boulevard, Arlington, VA. 22230.

Type of meeting: Closed.

Contact person: Lloyd E. Douglas, Senior Program Associate, National Science Foundation, 4201 Wilson Boulevard, Arlington, Va 22230. Telephone: (703) 306–1874.

Purpose of meeting: To provide advice and recommendations concerning proposals submitted to NSF for financial support.

Agenda: To review and evaluate proposals concerning the Research Planning Grant/Career Advancement Awards for Women and Minorities as part of the selection process for awards.

Reason for closing: The proposals being reviewed include information of a proprietary or confidential nature, including technical information; financial data, such as salaries and personal information concerning individuals associated with the proposals. These matters are exempt under 5 U.S.C. 552b(c) (4) and (6) of the Government in the Sunshine Act.

Dated: March 10, 1997.

Linda Allen-Benton,

Deputy Director, Division of Human Resource Management, Acting Committee Management Officer.

[FR Doc. 97–6456 Filed 3–13–97; 8:45 am]

BILLING CODE 7555–01–M

Special Emphasis Panel in Networking and Communications Research and Infrastructure; Notice of Meeting

In accordance with the Federal Advisory Committee Act (Pub. L. 92–463, as amended), the National Science Foundation announces the following meeting.

Name: Special Emphasis for Connections to the Internet Panel (#1207).

Dates and time: April 1–2, 1997; 8:30 a.m. to 5:00 p.m.

Place: National Science Foundation, 4201 Wilson Boulevard, Room 1175, Arlington, VA 22230.

Type of meeting: Closed.

Contact person(s): Mark Luker, Program Director, CISE/NCRI, Room 1175, National Science Foundation, 4201 Wilson Boulevard, Arlington, VA 22230, (703) 306–1950.

Purpose of meeting: To provide advice and recommendations concerning proposals submitted to NSF for financial support.

Agenda: To review and evaluate proposals submitted for the Connections to the Internet Program.

Reason for closing: The proposals being reviewed include information of a proprietary or confidential nature, including technical information; financial data, such as salaries, and personal information concerning individuals associated with the proposals. These matters are exempt under 5 U.S.C. 552b.(c) (4) and (6) of the Government in the Sunshine Act.

Dated: March 10, 1997.

Linda Allen-Benton,

Deputy Director, Division of Human Resource Management, Acting Committee Management Officer.

[FR Doc. 97–6452 Filed 3–13–97; 8:45 am]

BILLING CODE 7555–01–M

Special Emphasis Panel in Physics; Notice of Meeting

In accordance with the Federal Advisory Committee Act (Pub. L. 92–463, as amended), the National Science Foundation announces the following meeting.

Name: Special Emphasis Panel in Physics (1208).

Date and time: March 31, 1997 from 8:00AM to 5:00PM.

Place: Room 1020, NSR 4201 Wilson Blvd., Arlington, VA 22230.

Type of meeting: Closed.

Contact person: Dr. C. Denise Caldwell, Program Director, Room 1015, National Science Foundation, 4201 Wilson Blvd., Arlington, VA 22230. Telephone: (703) 306–1807; email, dcaldwel@nsf.gov

Purpose of meeting: To provide advise and recommendations concerning proposals submitted to NSF for financial support.

Agenda: to review and evaluate Atomic, Molecular, Optical and Plasma Physics Career proposals as part of the selection process for awards.

Reasons for closing: The project plans being reviewed include information of a proprietyar or confidential nature, including technical information; information on personnel and proprietary data for present and future subcontracts. These matters are exempt under 5 U.S.C. 552b(c) (4) and (6) of the Government in the Sunshine Act.

Dated: March 10, 1997.

Linda Allen-Benton,

Deputy Director, Division of Human Resource Management, Acting Committee Management Officer.

[FR Doc. 97–6451 Filed 3–13–97; 8:45 am]

BILLING CODE 7555–01–M

NORTHEAST DAIRY COMPACT COMMISSION

Notice of Price Regulation Procedure: Request for Additional Comments

AGENCY: Northeast Dairy Compact Commission.

SUMMARY: The Commission has previously sought comment, and held a hearing, on a variety of issues relating to the possible establishment of a compact over-order price regulation. See 61 FR 65604 dated December 13, 1996. In this notice, the Commission is providing an additional opportunity for public comment on issues identified in the earlier notice and in the December hearings, and on related subjects.

1. The Commission seeks comment on historical trends or patterns as well as statistical methods or data that relate to the issues identified in the earlier notice.

2. The Commission also seeks comment on the prevailing farm, wholesale and retail costs and/or prices, for bulk and/or packaged milk, both inside and outside the New England region; the impact, if any, on the various production and processing costs discussed in the earlier notice attributable to the distance that bulk and packaged product must travel to and from a processing facility; and the elasticity of demand for Class I fluid milk products.

3. The Commission seeks comment on the impact, if any on the retail price of milk in the New England region caused by movement of the epicenter of the milk supply away from the region's processing facilities, and the identification of statistical data and methodologies for measuring that impact.

4. The Commission seeks comment on the impact, if any, of a flat, regulated, minimum Class I price (a price that combines the federal Market Order and Compact over-order prices) on wholesale costs, prevailing market

premium surcharges, state over-order pricing programs, Class I prices in the areas of New England not regulated under Federal Market Order ι1 and any other potential impacts on the wholesale market for milk. The Commission also seeks comment on the level of premium surcharges that have been present in the New England market over time, the movement of bulk milk from New England to other regions of the country and the means for tracking the movement of packaged milk into New England from other regions.

5. The Commission seeks comment of the impact, if any, of such a flat Class I price on retail costs and prices, the fluid milk costs and price disbursements of the Women, Infants and Children Special Supplemental Nutrition Program of the United States Child Nutrition Act of 1966, and/or the fluid milk procurement process of school lunch programs. The Commission also seeks comment on the means to assess these impacts.

6. The Commission seeks comment on the most appropriate means to account for its responsibility to reimburse the Commodity Credit Corporation (CCC) for CCC purchases attributable to an increase in milk production in the New England region above the national average rate of increase.

7. The Commission also seeks comment on the appropriate, necessary and feasible, action to take, as required by the Compact, to ensure that Compact over-order price regulation does not result in additional supplies of milk.

8. The Commission is considering a possible Compact over-order price regulation that will be based, at least in part, on an adjustment for inflation to the Class I, fluid milk price, over time. The Commission seeks comment on the advisability of such an approach, as well as possible methodologies for determining the impact that such an adjustment would have on the Class I, fluid milk price, over time.

9. The Commission also seeks comment on any other issue of concern relating to establishment of a Compact over-order price regulation.

DATES: Comments and any exhibits, accompanied by affidavit, must be received by March 31, 1997.

Additional, reply comments, accompanied by affidavit, must be received by April 9, 1997.

ADDRESSES: Comments and exhibits should be submitted to: Northeast Dairy Compact Commission, 43 State Street, PO Box 1058, Montpelier, VT 05601–1058, (802) 229–1941 (phone), (802) 229–2028 (fax).

Authority: This notice is issued under the following authority:

(a) Article V, Section 11 of the Northeast Interstate Dairy Compact, and all other applicable Articles and Sections, as approved by Section 147 of the Federal Agricultural Improvement and Reform Act (FAIR ACT), P.L. 104–127, and as thereby set forth in S.J. Res. 28(1)(b) of the 104th Congress; Finding of Compelling Public Interest by United States Department of Agriculture Secretary Dan Glickman, August 9, 1996.

(b) Bylaws of the Northeast Dairy Compact Commission, adopted November 21, 1996.

(c) Resolution adopted by Northeast Dairy Compact Commission, November 21, 1996.

(d) Resolution adopted by Northeast Dairy Compact Commission, March 7, 1997.

Daniel Smith,

Executive Director.

[FR Doc. 97–6496 Filed 3–13–97; 8:45 am]

BILLING CODE 1650–01–M

NUCLEAR REGULATORY COMMISSION

Agency Information Collection Activities: Proposed Collection; Comment Request

AGENCY: U. S. Nuclear Regulatory Commission (NRC)

ACTION: Notice of pending NRC action to submit an information collection request to OMB and solicitation of public comment.

SUMMARY: The NRC is preparing a submittal to OMB for review of continued approval of information collections under the provisions of the Paperwork Reduction Act of 1995 (44 U.S.C. Chapter 35).

Information pertaining to the requirement to be submitted:

1. The title of the information collection: 10 CFR Part 40, ''Domestic Licensing of Source Material,'' NRC Form 244, ''Registration Certificate—Use of Depleted Uranium under General License,'' and NRC Form 484, ''Detection Monitoring Data Report.''

2. Current OMB approval number: 3150–0020 for 10 CFR Part 40 and NRC Form 484 and 3150–0031 for NRC Form 244.

3. How often the collection is required: Reports required under 10 CFR

Part 40 are collected and evaluated on a continuing basis as events occur. There is a one-time submittal of information to receive a license. Renewal applications need to be submitted every 5 to 10 years. Information in previous applications may be referenced without being resubmitted. In addition, recordkeeping must be performed on an on-going basis. NRC Form 244 is submitted when depleted uranium is received or transferred under general license. NRC Form 484 is submitted biannually to report groundwater data necessary to implement EPA groundwater standards.

4. Who is required or asked to report: 10 CFR Part 40: Applicants for and holders of NRC licenses authorizing the receipt, possession, use, or transfer of radioactive source and byproduct material. NRC Form 244: Persons receiving, possessing, using, or transferring depleted uranium under the general license established in 10 CFR 40.25(a). NRC Form 484: Uranium recovery facility licensees reporting groundwater monitoring data pursuant to 10 CFR 40.65.

5. The number of annual respondents:

10 CFR Part 40: 156 for NRC licensees and 172 for Agreement State licensees.

NRC Form 244: 20 for NRC licensees and 40 for Agreement State licensees.

NRC Form 484: Included in 10 CFR Part 40, above.

6. The number of hours needed annually to complete the requirement or request: 10 CFR Part 40: 26,049 hours for reporting requirements and 9,019 hours for recordkeeping requirements, or a total of 35,068 hours for NRC licensees; 28,083 hours for reporting requirements and 9,398 hours for recordkeeping requirements, or a total of 37,481 hours for Agreement State licensees. NRC Form 244: 20 hours for NRC licensees and 40 hours for Agreement State licensees for reporting requirements. NRC Form 484: Included in 10 CFR Part 40, above.

7. Abstract: 10 CFR Part 40 establishes requirements for licenses for the receipt, possession, use, and transfer of radioactive source and byproduct material. NRC Form 244 is used to report receipt and transfer of depleted uranium under general license, as required by 10 CFR Part 40. NRC Form 484 is used to report certain groundwater monitoring data required by 10 CFR Part 40 for uranium recovery licensees. The application, reporting, and recordkeeping requirements are necessary to permit the NRC to make a determination on whether the possession, use, and transfer of source and byproduct material is in conformance with the Commission's regulations for protection of public health and safety.

Submit, by May 13, 1997, comments that address the following questions:

1. Is the proposed collection of information necessary for the NRC to properly perform its functions? Does the information have practical utility?

2. Is the burden estimate accurate?

3. Is there a way to enhance the quality, utility, and clarity of the information to be collected?

4. How can the burden of the information collection be minimized, including the use of automated collection techniques or other forms of information technology?

A copy of the draft supporting statement may be viewed free of charge at the NRC Public Document Room, 2120 L Street NW, (lower level), Washington, DC. Members of the public who are in the Washington, DC, area can access this document via modem on the Public Document Room Bulletin Board (NRC's Advanced Copy Document Library), NRC subsystem at FedWorld, 703–321–3339. Members of the public who are located outside of the Washington, DC, area can dial FedWorld, 1–800–303–9672, or use the FedWorld Internet address: fedworld.gov (Telnet). The document will be available on the bulletin board for 30 days after the signature date of this notice. If assistance is needed in accessing the document, please contact the FedWorld help desk at 703–487–4608. Additional assistance in locating the document is available from the NRC Public Document Room, nationally at 1–800–397–4209, or within the Washington, DC, area at 202–634–3273.

Comments and questions about the information collection requirements may be directed to the NRC Clearance Officer, Brenda Jo. Shelton, U.S. Nuclear Regulatory Commission, T–6 F33, Washington, DC 20555–0001, by telephone at (301) 415–7233, or by Internet electronic mail at BJS1@NRC.GOV.

Dated at Rockville, Maryland, this 10th day of March 1997.

For the Nuclear Regulatory Commission.

Gerald F. Cranford,

Designated Senior Official for Information Resources Management.

[FR Doc. 97–6478 Filed 3–13–97; 8:45 am]

BILLING CODE 7590–01–P

[Docket No. 27–47]

Consideration of an Amendment to a License for Disposal of Low-Level Radioactive Waste Containing Special Nuclear Material by Chem-Nuclear systems, Incorporated and Transfer of License to South Carolina, and an Opportunity for a Hearing

SUMMARY: The U.S. Nuclear Regulatory Commission is considering a request to amend License No. 12–13536–01. This license is issued to Chem-Nuclear Systems, Incorporated (CNSI) for the disposal of wastes containing special nuclear material (SNM) in the low-level radioactive waste (LLW) disposal facility, located near Barnwell, South Carolina. NRC licenses this facility under 10 CFR Part 70. The amendment would reduce the SNM possession limit of the license, and NRC would subsequently transfer the license to the State of South Carolina. South Carolina already regulates disposal of source and byproduct material at the Barnwell facility.

FOR FURTHER INFORMATION CONTACT: Timothy E. Harris, Low-Level Waste and Decommissioning Projects Branch, Division of Waste Management, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001. Telephone: (301) 415–6613. Fax.: (301) 415–5398.

BACKGROUND: The LLW disposal facility located near Barnwell, South Carolina, is licensed by NRC for possession, storage, and disposal of SNM. The State of South Carolina licenses disposal of source and byproduct material at the facility. In correspondence dated December 20, 1996, CNSI requested termination of its NRC SNM license. As justification for the request, CNSI noted a reduction in SNM-bearing waste volumes and the diminished cost effectiveness of the license. CNSI requested that the South Carolina Department of Environmental Control (SCDHEC) amend its South Carolina license to allow possession of up to 350 grams of SNM. Currently, the NRC license permits possession, storage, and disposal of greater than critical mass quantities of SNM, and acknowledges that the State-regulated source and byproduct disposal activities constitute the major site activities. Possession, storage, and disposal of less than critical mass quantities can be regulated by Agreement States, in accordance with 10 CFR Part 150 (Exemptions and Continued Regulatory Authority in Agreement States and in Offshore Waters Under Section 274). Specifically, § 150.11 defines less than critical mass limits of SNM which can be regulated by Agreement States.

To implement CNSI's request, NRC plans to amend the license to reduce the SNM possession limit to those specified in § 150.11 and subsequently transfer the license to South Carolina. This amendment will result in a change in process operations. The reduction in possession limit will not significantly change the types or amounts of effluents that may be released offsite, will not increase individual or cumulative occupational radiation exposure, will not be a significant construction impact, and will not significantly increase the potential for or consequences from radiological accidents. Accordingly, the amendment is categorically exempt from an environmental assessment under 10 CFR 51.22(c)(11). Following issuance of this amendment, NRC will transfer the license to SCDHEC.

NRC provides notice that this is a proceeding on an application for a license amendment and transfer falling within the scope of Subpart L, ''Informal Hearing Procedures for Adjudication in Materials Licensing Proceedings,'' of NRC's rules and practice for domestic licensing proceedings in 10 CFR part 2. Pursuant to § 2.1205(a), any person whose interest may be affected by this proceeding may file a request for a hearing in accordance with § 2.1205(c). A request for a hearing must be filed within thirty (30) days of the date of publication of this Federal Register notice.

In addition to meeting other applicable requirements of 10 CFR Part 2 of NRC's regulations, a request for a hearing filed by a person other than an applicant must describe in detail:

1. The interest of the requester in the proceeding;

2. How that interest may be affected by the results of the proceeding, including the reasons why the requester should be permitted a hearing, with particular reference to the factors set out in § 2.1205(g);

3. The requester's areas of concern about the licensing activity that is the subject matter of the proceeding; and

4. The circumstances establishing that the request for a hearing is timely in accordance with § 2.1205(c).

In accordance with 10 CFR § 2.1205(e), each request for a hearing must also be served, by delivering it personally or by mail, to:

1. The applicant, Chem-Nuclear Systems, Inc., 140 Stoneridge Drive, Columbia, South Carolina 29210, Attention: Mr. William House, and;

2. NRC staff, by delivery to the Secretary, U.S. Nuclear Regulatory Commission, Washington, D.C., 20555–0001. Attention: Docketing and Service Branch; or hand-deliver comments to: 11555 Rockville Pike, Rockville, MD between 7:45 a.m. and 4:15 p.m., Federal workdays.

For further details with respect to this action, the application for amendment request is available for inspection at NRC's Public Document Room, 2120 L Street NW., Washington, DC 20555.

Dated at Rockville, Maryland, this 10th day of March 1997.

For the Nuclear Regulatory Commission.

John W.N. Hickey,

Chief, Low-Level Waste and Decommissioning Projects Branch, Division of Waste Management Office of Nuclear Material Safety and Safeguards.

[FR Doc. 97–6479 Filed 3–13–97; 8:45 am]

BILLING CODE 7590–01–P

[Docket Nos. STN 50–528, STN 50–529, and STN 50–530]

Arizona Public Service Company; Palo Verde Nuclear Generating Station, Units Nos. 1, 2, and 3 Environmental Assessment and Finding of No Significant Impact

The U.S. Nuclear Regulatory Commission (the Commission) is considering issuance of amendments to Facility Operating License Nos. NPF–41, NPF–51, and NPF–74, issued to Arizona Public Service Company (the licensee), for operation of the Palo Verde Nuclear Generating Station, Unit Nos. 1, 2, and 3, located in Maricopa County, Arizona.

Environmental Assessment

Identification of the Proposed Action

The proposed action would modify the licenses for Palo Verde Nuclear Generating Station (PVNGS), Unit Nos. 1, 2, and 3, to authorize incorporation in the Updated Final Safety Analysis Report (UFSAR) a revised large-break loss-of-coolant accident (LBLOCA) analysis. The revised LBLOCA analysis addresses a previously unanalyzed release path through the steam generators to the atmosphere.

The proposed action is in accordance with the licensee's application dated May 2, 1995, as supplemented by letter March 7, 1996.

The Need for the Proposed Action

The proposed action would permit the UFSAR to be revised to address a previously unanalyzed release path through the steam generators to the atmosphere for the LBLOCA. This would incorporate this release path into the licensing basis of the facility.

Environmental Impacts of the Proposed Action

The Commission has completed its evaluation of the proposed action and concludes that there are no significant environmental considerations involved with the proposed action. The incorporation in the UFSAR for PVNGS Unit Nos. 1, 2, and 3 of the previously unanalyzed release path in the LBLOCA does not affect the design or operation of the plant, does not involve any modifications to the plant or any increase in the licensed power for the plant, does not affect plant effluents, does not increase the probability of any postulated accident and will not create a new accident, and does not create any new or unreviewed environmental impacts that were not considered in the Final Environmental Statement (FES).

The FES did not consider in its evaluation of a LBLOCA, the leakage of containment atmosphere through the steam generators and to the public. Assessment of environmental impacts of the LBLOCA accounted for radiological releases from the containment and emergency core cooling system into the environment. For the revised analysis of the LBLOCA, atmospheric releases through the steam generators could be considered part of the leakage of containment atmosphere into the environment, although the location of release is different. The FES analyzed radiological releases from the steam generators to the environment in the evaluation of the steam generator tube rupture accident. Thus, the FES evaluated releases to the environment from steam generators, but this release pathway was not included in the LBLOCA analysis. The revised LBLOCA analysis does not significantly increase the environmental impacts of postulated accidents which are discussed in Section 5.9.2 of the FES, and is of no measurable environmental impact.

Alternatives to the Proposed Action

Since the Commission has concluded there is no measurable environmental impact associated with the proposed action, any alternatives with equal or greater environmental impact need not be evaluated. As an alternative to the proposed action, the staff considered denial of the proposed action. Denial of the application would result in no change in current environmental impacts. The environmental impacts of the proposed action and the alternative action are similar.

Alternative Use of Resources

This action does not involve the use of any resources not previously considered in the ‘‘Final Environmental Statement Related to the Operation of the Palo Verde Nuclear Generating Station, Units 1, 2, and 3,’’ dated February 1982.

Agencies and Persons Consulted

In accordance with its stated policy, on March 7, 1997, the staff consulted with the Arizona State official, Mr. William Wright of the Arizona Radiation Regulatory Agency, regarding the environmental impact of the proposed action. The State official had no comments.

Finding of No Significant Impact

Based upon the environmental assessment, the Commission concludes that the proposed action will not have a significant effect on the quality of the human environment. Accordingly, the Commission has determined not to prepare an environmental impact statement for the proposed action.

For further details with respect to the proposed action, see the licensee's letter dated May 2, 1995, as supplemented by letter dated March 7, 1996, which is available for public inspection at the Commission's Public Document Room, The Gelman Building, 2120 L Street, NW., Washington, DC, and at the local public document room located at the Phoenix Public Library, 1221 N. Central Avenue, Phoenix, Arizona 85004.

Dated at Rockville, Maryland, this 10th day of March 1997.

For the Nuclear Regulatory Commission.

James W. Clifford,

Senior Project Manager, Project Directorate IV–2, Division of Reactor Projects—III/IV, Office of Nuclear Reactor Regulation.

[FR Doc. 97–6481 Filed 3–13–97; 8:45 am]

BILLING CODE 7590–01–P

[Docket No. 50–271]

Vermont Yankee Nuclear Power Corporation; Vermont Yankee Nuclear Power Station; Environmental Assessment and Finding of No Significant Impact

The U.S. Nuclear Regulatory Commission (the Commission) is considering issuance of an exemption for Facility Operating License No. DPR–28, issued to Vermont Yankee Nuclear Power Corporation (the licensee), for operation of the Vermont Yankee Nuclear Power Station (the facility) located in Windham County, Vermont.

Environmental Assessment

Identification of Proposed Actions

The proposed exemption would grant relief in certain outdoor areas of the protected area of the facility to allow use of security lighting for outdoor access and egress and the performance of one specified task in either of two locations for compliance with Section III.J of Appendix R to 10 CFR part 50. The exemption would include outdoor portions of the protected area for access and egress and for supply of nitrogen from either of two outdoor locations: (1) the 15,000 gallon liquid nitrogen containment inerting tank located outdoors, east of the reactor building, or (2) nitrogen storage bottles located on the west wall of the reactor building equipment air lock.

The proposed exemption is in accordance with the licensee's application for exemption dated June 17, 1996.

The Need for the Proposed Actions

The need for this action arises for certain Appendix R fire scenarios whose safe shutdown strategy does not immediately depressurize the reactor and uses low pressure injections systems, and thus requires the safety relief valves (SRVs) to be actuated multiple times during a cooldown. Although each SRV accumulator has capacity for at least five valve strokes, a long term source of nitrogen, beyond the capacity of the SRV accumulators is required in order to provide for additional valve strokes for some scenarios. The nitrogen may be provided from either of two nitrogen storage locations.

Environmental Impacts of the Proposed Actions

The Commission has completed its evaluation of the proposed exemption and concludes that the proposed exemption will provide sufficient fire protection that there is no increase in the risk of fires at the facility. Consequently, the probability of fires has not been increased and the post-fire radiological releases will not be greater than previously determined, nor does the proposed exemption otherwise affect radiological plant effluents.

The proposed exemption affects only the source of illumination credited for safe shutdown functions. No physical change results from the proposed exemption, and, as discussed above, the probability of fires has not been increased. Therefore, the change will not increase the probability or consequences of accidents. No changes are being made in the types of any effluents that may be released offsite, and there is no significant increase in the allowable individual or cumulative occupational radiation exposure. Accordingly, the Commission concludes that there are no significant radiological environmental impacts associated with the proposed actions.

With regard to potential nonradiological impacts, the proposed actions involve features located entirely within the restricted area as defined in 10 CFR part 20. They do not affect nonradiological plant effluents and have no other environmental impact. Accordingly, the Commission concludes that there are no significant nonradiological environmental impacts associated with the proposed actions.

Alternatives to the Proposed Actions

Since the Commission has concluded there is no measurable environmental impact associated with the proposed actions, any alternatives with equal or greater environmental impact need not be evaluated. As an alternative to the proposed actions, the staff considered denial of the proposed actions. Denial of the application would result in no change in current environmental impacts. The environmental impacts of the proposed actions and the alternative action are similar.

Alternative Use of Resources

These actions do not involve use of resources not previously considered in the Final Environmental Statement for the Vermont Yankee Nuclear Power Station.

Agencies and Persons Consulted

In accordance with its stated policy, on February 26, 1997, the staff consulted with the Vermont State official, Mr. William K. Sherman of the Vermont Department of Public Service, regarding the environmental impact of the proposed actions. The State official had no comments.

Finding of No Significant Impact

Based upon the environmental assessment, the Commission concludes that the proposed actions will not have a significant effect on the quality of the human environment. Accordingly, the Commission has determined not to prepare an environmental impact statement for the proposed exemption.

For further details with respect to the proposed actions, see the application dated June 17, 1996, which is available for public inspection at the Commission's Public Document Room, The Gelman Building, 2120 L Street, NW., Washington, DC, and at the local public document room located at the Brooks Memorial Library, 224 Main Street, Brattleboro, VT 05301.

Dated at Rockville, Maryland this 5th day of March 1997.

For the Nuclear Regulatory Commission.

Patrick D. Milano,

Acting Director, Project Directorate I–3, Division of Reactor Projects—I/II, Office of Nuclear Reactor Regulation.

[FR Doc. 97–6482 Filed 3–13–97; 8:45 am]

BILLING CODE 7590–01–P

Core Research Capabilities for the Office of Nuclear Regulatory Research; Meeting

AGENCY: Nuclear Regulatory Commission.

ACTION: Notice of meeting.

SUMMARY: NRC staff and industry will discuss the core research capabilities of the Office of Nuclear Regulatory Research.

DATES: March 25, 1997, 9:00 a.m.–4:00 p.m.

ADDRESSES: Room O–1F7/9, One White Flint North (OWFN) Building, 11545 Rockville Pike, Rockville, MD.

FOR FURTHER INFORMATION CONTACT: Mr. Lloyd Donnelly, Office of Nuclear Regulatory Research, U.S. Nuclear Regulatory Commission, Washington DC 20555 Telephone (301) 415–5828.

SUPPLEMENTARY INFORMATION: The purpose of this meeting is to discuss the core research capabilities of the Office of Nuclear Regulatory Research in order for this office to continue active participation in cooperative safety research activities with other government agencies including DOE, industry, and international organizations concerned with nuclear reactor safety.

Dated at Rockville, Maryland, this 10th day of March 1997.

For the Nuclear Regulatory Commission.

David L. Morrison,

Director, Office of Nuclear Regulatory Research.

[FR Doc. 97–6477 Filed 3–13–97; 8:45 am]

BILLING CODE 7590–01–P

[Docket Nos. 50–498 and 50–499]

South Texas Project; Local Public Document Room

Notice is hereby given that the Nuclear Regulatory Commission (NRC) will not be relocating the local public document room (LPDR) for records pertaining to Houston Lighting and Power Company's South Texas Project. The LPDR will remain at the J.M. Hodges Library, Wharton County Junior College, 911 Boling Highway, Wharton, Texas. The Library Director has informed the NRC staff that they will continue with the maintenance and operation of the South Texas LPDR.

Dated at Rockville, Maryland, this 10th day of March 1997.

For the Nuclear Regulatory Commission.

Russell A. Powell,

Chief, Freedom of Information/Local Public Document Room Branch, Office of Information Resources Management.

[FR Doc. 97–6480 Filed 3–13–97; 8:45 am]

BILLING CODE 7590–01–P

PENSION BENEFIT GUARANTY CORPORATION

Interest Assumption for Determining Variable-Rate Premium; 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 are derivable 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 home page (http://www.pbgc.gov).

DATES: The interest rate for determining the variable-rate premium under part 4006 applies to premium payment years beginning in March 1997. The interest assumptions for performing multiemployer plan valuations following mass withdrawal under part 4281 apply to valuation dates occurring in April 1997.

FOR FURTHER INFORMATION CONTACT: Harold J. Ashner, Assistant General Counsel, Office of the General Counsel, Pension Benefit Guaranty Corporation, 1200 K Street, NW., Washington, DC 20005, 202–326–4024 (202–326–4179 for TTY and TDD).

SUPPLEMENTARY INFORMATION:

Variable-Rate Premiums

Section 4006(a)(3)(E)(iii)(II) of the Employee Retirement Income Security Act of 1974 and § 4006.4(b)(1) of the PBGC's regulation on Premium Rates (29 CFR part 4006) prescribe use of an assumed interest rate in determining a single-employer plan's variable-rate premium. The rate is a specified percentage (currently 80 percent) of the annual yield on 30-year Treasury securities for the month preceding the beginning of the plan year for which premiums are being paid (the ''premium payment year''). The yield figure is reported in Federal Reserve Statistical Releases G.13 and H.15.

The assumed interest rate to be used in determining variable-rate premiums for premium payment years beginning in March 1997 (*i.e.*, 80 percent of the yield figure for February 1997) is 5.35 percent. The following table lists the assumed interest rates to be used in determining variable-rate premiums for premium payment years beginning between April 1996 and March 1997.

For premium payment years beginning in	The required interest rate is
April 1996	5.28
May 1996	5.43
June 1996	5.54
July 1996	5.65
August 1996	5.62
September 1996	5.47
October 1996	5.62
November 1996	5.45
December 1996	5.18
January 1997	5.24
February 1997	5.46
March 1997	5.35

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 1997 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, D.C., on this 10th day of March 1997.

John Seal,

Acting Executive Director, Pension Benefit Guaranty Corporation.

[FR Doc. 97–6488 Filed 3–13–97; 8:45 am]

BILLING CODE 7708–01–P

SECURITIES AND EXCHANGE COMMISSION

Request for Public Comment

Upon Written Request, Copies Available From: Securities and Exchange Commission, Office of Filings and Information Services, Washington, DC 20549.

Extension:
- Rule 12b–1, SEC File No. 270–188, OMB Control No. 3235–0212
- Rule 17f–1, SEC File No. 270–236, OMB Control No. 3235–0222
- Form N–SAR, SEC File No. 270–292, OMB Control No. 3235–0330
- Form N–17f–1, SEC File No. 270–316, OMB Control No. 3235–0359
- Form N–17f–2, SEC File No. 270–317, OMB Control No. 3235–0360
- Form ADV–E, SEC File No. 270–318, OMB Control No. 3235–0361
- Rule 30b2–1, SEC File No. 270–213, OMB Control No. 3235–0220

Notice is hereby given that pursuant to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), the Securities and Exchange Commission (''Commission'') is publishing for public comment the following summary of previously approved information collection requirements.

Rule 12b–1 under the Investment Company Act of 1940 (''1940 Act'') permits a registered open-end management investment company (''mutual fund'') to distribute its own shares and pay expenses of distribution provided, among other things, the mutual fund adopts a written plan, and has in writing any agreements relating to the implementation of the plan. The rule requires the plan to be approved by the mutual fund's directors and shareholders; provides for quarterly reports to the board regarding amounts spent under the plan; requires the board to review the plan at least annually; requires board and shareholder approval for certain changes to the plan; and imposes certain recordkeeping requirements.

It is estimated that approximately 4,165 mutual funds rely on the rule each year, and the average annual burden per fund is estimated to be 40 hours. The total annual burden for all mutual funds relying on the rule is estimated to be 166,600 hours.

Rule 17f–1 under the 1940 Act provides that any registered management investment company (''fund'') that wishes to place its assets in the custody of a national securities exchange may do so only pursuant to a written contract that must be ratified initially and approved annually by a majority of the fund's board of directors and that contains certain specified provisions. The rule also requires that the fund's assets in such custody be examined by an independent public accountant at least three times during the fund's fiscal year. The rule requires the written contract and the certificate of each examination to be transmitted to the Commission. The annual burden of the rule's requirements is estimated to be about 2½ hours for each of approximately 31 funds that maintain their assets with a national securities exchange, for an estimated total of 77.5 burden hours annually.

Form N–SAR under the 1940 Act is used by registered investment companies for annual or semi-annual reports required to be filed with the Commission. The annual burden is approximately to 31.5 hours.

Form N–17f–1 is the cover sheet for accountant examination certificates filed pursuant to rule 17f–1 under the 1940 Act by management investment companies maintaining securities or other investments with companies that are members of a national securities exchange. The time needed for investment companies to comply with the requirements of the form is approximately nine minutes annually.

Form N–17f–2 is the coversheet for accountant examination certificates filed pursuant to rule 17f–2 under the 1940 Act by management investment companies maintaining custody of securities or other investments. The time needed for investment companies to comply with the requirements of the form is approximately nine minutes annually.

Form ADV–E is the coversheet for accountant examination certificates filed pursuant to rule 206(4)–2 under the Investment Advisers Act by investment advisers retaining custody of client securities or funds. Registrants each spend approximately three minutes annually to comply with the requirements of the form.

Rule 30b2–1 requires the filing of four copies of every periodic or interim report transmitted by or on behalf of any registered investment company to its shareholders. The annual burden of filing the reports is estimated to be negligible.

The estimate of average burden hours is made solely for the purposes of the Paperwork Reduction Act, and is not derived from a comprehensive or even a representative survey or study of the cost of SEC rules and forms.

Written comments are requested on: (a) Whether the collections of information are necessary for the proper performance of the functions of the Commission, including whether the information has practical utility; (b) the accuracy of the Commission's estimate of the burdens of the collection of information; (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 respondents, including through the use of automated collection techniques or other forms of information technology. Consideration will be given to comments and suggestions submitted in writing within 60 days of this publication.

Direct your written comments to Michael E. Bartell, Associate Executive Director, Office of Information Technology, Securities and Exchange Commission, 450 5th Street, NW., Washington, DC 20549.

Dated: March 6, 1997.

Margaret H. McFarland,

Deputy Secretary.

[FR Doc. 97–6421 Filed 3–13–97; 8:45 am]

BILLING CODE 8010–01–M

[Rel. No. IA–1617; 803–104]

Brac Associates Limited Liability Company, et al.; Notice of Application

March 7, 1997.

AGENCY: Securities and Exchange Commission (''SEC'').

ACTION: Notice of application for exemption under the Investment Advisers Act of 1940 (the ''Advisers Act'').

Applicants: Brac Associates Limited Liability Company (''Brac'') and Lexington Capital Partners, L.P. (''Lexington'').

Relevant Act Sections: Order requested under section 205(e) of the Advisers Act for an exemption from section 205(a)(1) of the Advisers Act.

Summary of Application: Applicants are a limited liability company and a limited partnership that a family formed to facilitate and simplify the investment of its assets and multiple trusts established by family members. Applicants request an order to permit registered investment advisers to charge them performance-based advisory fees.

Filing Dates: The application was filed on August 29, 1996, and amended on February 12, 1997.

Hearing or Notification of Hearing: An order granting the application will be issued unless the SEC orders a hearing. Interested persons may request a hearing by writing to the SEC's Secretary and serving applicants with a copy of the request, personally or by mail. Hearing requests should be received by the SEC by 5:30 p.m. on April 2, 1997, 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 SEC's Secretary.

ADDRESSES: Secretary, SEC, 450 Fifth Street, NW., Washington, DC 20549. Applicants, c/o Antaeus Enterprises, Inc., Suite 3020, 420 Lexington Avenue, New York, New York 10170.

FOR FURTHER INFORMATION CONTACT: Brian T. Hourihan, Senior Counsel, at (202) 942–0526, or Mary Kay Frech, Branch Chief, at (202) 942–0564 (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 from the SEC's Public Reference Branch.

Applicants' Representations

1. Applicants were formed by the Beinecke family to facilitate and simplify the investment of Beinecke family assets and trusts established by Beinecke family members. Applicants are excepted from registration under the Investment Company Act of 1940 under section 3(c)(1). Applicants request an order under section 205(e) of the Advisers Act granting an exemption from section 205(a)(1) of the Advisers Act to permit registered investment advisers to charge them a performance-based advisory fee.

2. Brac and Lexington are essentially Beinecke family investment vehicles. Brac is a Delaware limited liability company that is owned by Antaeus Enterprises, Inc. (''Antaeus''), one individual Beinecke family member, and four irrevocable trusts (the trustees and beneficiaries of which are all Beinecke family members). Lexington is a Delaware limited partnership that is owned by Antaeus, four individual Beinecke family members, fifteen irrevocable trusts and one revocable grantor trust (the trustees and beneficiaries of which are all Beinecke family members), and two investment vehicles established by Mr. Robert L. Bael, a long-term family employee and an executive officer of Antaeus (together, the ''Bael Partners'').

3. Brac's managing member and Lexington's general partner, Antaeus, is responsible for making investment decisions for applicants. Antaeus is an investment management company owned by four trusts established by William Sperry Beinecke for the benefit of his four children. Antaeus acts as coordinator and administrator of the Beinecke family assets, including certain trusts. Antaeus invests in publicly traded and privately held fixed income and equity securities and investment partnerships, with a portion of its assets invested in applicants. No management, performance, or other fee is charged to the members of Brac or the limited partners of Lexington.

4. Applicants state that they want to participate in investment opportunities managed by registered investment advisers that seek to charge applicants a performance-based advisory fee pursuant to rule 205–3 of the Advisers Act. Applicants represent that neither themselves, Antaeus, any other Beinecke family member who acts as trustee of any Beinecke trust, any other Beinecke family member who is a beneficiary of any of the Beinecke trusts, nor any partner, trustee or beneficiary of the Bael Partners has any relationship with, or is an affiliate or an interested

person of, any such registered investment adviser.

5. All current members of Brac and the majority of limited partners of Lexington, as well as the general partner, have a net worth exceeding $1,000,000 and thereby satisfy the client eligibility requirements of paragraph (b) of rule 205–3. However, nine trusts which are limited partners of Lexington fail individually to satisfy the net worth requirements of rule 205–3(b) (the ''Non-qualifying Trusts'').[1] Six of the Non-qualifying Trusts have been established on behalf of six of the grandchildren of William Sperry Beinecke, whose ages range form 7 to 17. The seventh Non-qualifying Trust is a grantor trust which was established by a seventh grandchild of William Sperry Beinecke upon reaching the age of majority. Such grandchildren are the ultimate beneficiaries of (a) the four trusts which own Antaeus, a corporation having assets with an estimated market value in excess of $50 million, and (b) the trusts which are qualifying limited partners of Lexington. The eighth Non-qualifying Trust is a testamentary trust beneficially owned by the four adult children of William Sperry Beinecke, each of whom has assets in excess of $1,000,000. The ninth Non-qualifying Trust is beneficially owned by the three adult children of Mr. Bael. Each of the Bael children is expected to be an eventual beneficiary of the estate of his or her parents to the extent of more than $1,000,000. As a result of the limited partnership interests held by the Non-qualifying Trusts, Lexington may not be treated as satisfying the client eligibility requirements in paragraph (b) of rule 205–3.

6. Applicants request that any relief be applicable not only with respect to the Non-qualifying Trusts that are currently limited partners of Lexington, but also with respect to future Beinecke family trusts and custodianships under the Uniform Gift to Minors Act (''UGMA'') having Beinecke family members as trustee or custodian, as applicable, that may become limited partners or members, as the case may be, of applicants in the future. Such future trusts and custodianships will comply with the representations set forth in the application.

Applicants' Legal Analysis.

1. Section 205(a)(1) of the Advisers Act generally prohibits a registered investment adviser from receiving compensation on the basis of a share of capital gains in or capital appreciation of a client's account, or any portion thereof. Section 205(e) of the Advisers Act provides that the SEC may exempt any person or transaction, or any class or classes of persons or transactions from section 205(a)(1) of the Advisers Act if and to the extent that the exemption relates to an investment advisory agreement with any person that the SEC determines does not need the protection of section 205(a)(1), on the basis of such factors as financial sophistication, net worth, knowledge of and experience in financial matters, amount of assets under management, relationship with a registered investment adviser, and such other factors as the SEC determines are consistent with section 205.

2. Rule 205–3 provides an exemption from the prohibition against performance-based compensation in section 205(a)(1) provided the conditions of the rule are satisfied. Paragraph (b)(1) of rule 205–3 requires each client entering into an investment advisory contract that provides for such compensation to be: (a) A natural person or a company who immediately after entering into the contract has at least $500,000 under management of the investment adviser; or (b) a person who the registered investment adviser reasonably believes, prior to entering into the contract, is a natural person or a company whose net worth at the time the contract is entered into exceeds $1,000,000. Paragraph (b)(2) of the rule provides that the term ''company'' does not include private investment companies such as applicants unless each of the equity owners is a natural person or a company, as defined therein, that meets the eligibility requirements of paragraph (b)(1) of the rule. A trust is expressly included in the definition of a ''company.'' Applicants believe that a custodianship should be viewed as a type of trust for this purpose because, under UGMA, a custodian is a fiduciary whose duties and powers are similar to those of a trustee.

3. The client eligibility requirements of rule 205–3 reflect the SEC's recognition that certain high net worth clients have the capacity to bear the additional risks of performance fees, as well as the ability to protect themselves against the potential abuses of performance fees. Applicants are unable to rely on the rule because the Non-qualifying Trusts do not satisfy the $500,000 under management or the $1,000,000 net worth requirement. However, applicants believe that exemptive relief is appropriate under and consistent with the purposes of section 205(a)(1) and complies with the factors specified in section 205(e) of the Advisers Act because: (a) Antaeus, the entity which makes the investment decisions for applicants, satisfies the net worth requirement, is financially sophisticated with very substantial knowledge of and experience in financial matters, and is fully able to assess the potential risks of performance fees; (b) each trustee of the Non-qualifying Trusts is a family member of the beneficiaries thereof who, in addition to possessing a high level of financial sophistication and very substantial knowledge of and experience in financial matters, have substantial personal wealth, entitlements or expectancies invested in applicants, and may reasonably be presumed to be acting in the best interests of the beneficiaries who are their close family members; and (c) the beneficiaries of the Non-qualifying Trusts have the financial means to bear the potential risks of performance fees, because each satisfies the net worth requirement if his or her entitlements and expectancies are aggregated for this purpose, and do not have a relationship with prospective registered investment advisers.

4. Because those executing investment authority for the Non-qualifying Trusts have such strong and intimate familial relationships to the beneficiaries, applicants believe that it is not unreasonable to presume that the commonality of such interest will result in the decision-maker behaving in the best interests of the beneficiaries. Except for the requested exemption for the Non-qualifying Trusts and custodianships, the requirements of rule 205–3 are satisfied in all respects. Thus, applicants believe that granting the requested exemption is appropriate under and consistent with the purposes of section 205(a)(1) and the factors specified in section 205(e).

For the Commission, by the Division of Investment Management, under delegated authority.

Margaret H. McFarland,

Deputy Secretary.

[FR Doc. 97–6420 Filed 3–13–97; 8:45 am]

BILLING CODE 8010–01–M

[1] It is unlikely that the alternative requirement of having at least $500,000 under the management of the investment adviser will be satisfied, because applicants invest their assets in multiple private investment companies.

[Rel. No. IC–22549; 812–10328]

Great-West Life & Annuity Insurance Company, et al.

March 10, 1997.

AGENCY: The Securities and Exchange Commission (''Commission'').

ACTION: Notice of application for an order pursuant to the Investment Company Act of 1940 (''1940 Act'').

APPLICANTS: Great-West Life & Annuity Insurance Company (''GWL&A''), FutureFunds Series Account (''Separate Account''), and BenefitsCorp Equities, Inc. (''BCE'').

RELEVANT 1940 ACT SECTIONS: Order requested pursuant to Sections 6(c), 17(b), and 26(b).

SUMMARY OF APPLICATION: Applicants request an order pursuant to Section 26(b) of the 1940 Act approving a proposed substitution of securities, and pursuant to Sections 6(c) and 17(b) of the 1940 Act exempting related transactions from Section 17(a) of the 1940 Act.

FILING DATE: The application was filed on September 6, 1996, and amended on January 10, 1997.

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 Secretary of the Commission 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 April 4, 1997, 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 Secretary of the Commission.

ADDRESSES: Secretary, Securities and Exchange Commission, 450 Fifth Street, N.W. Washington, D.C. 20549. Applicants, c/o W. Randolf Thompson, Esq., Jorden Burt Berenson & Johnson, LLP, 1025 Thomas Jefferson Street, N.W., Suite 400 East, Washington, D.C. 20007–0805.

FOR FURTHER INFORMATION CONTACT: Kevin M. Kirchoff, Branch Chief, Office of Insurance Products (Division of Investment Management), at (202) 942–0672.

SUPPLEMENTARY INFORMATION: The following is a summary of the application. The complete application is available for a fee from the Public Reference Branch of the Commission.

Applicants' Representations

1. GWL&A, a Colorado stock life insurance company, does business in the District of Columbia, Puerto Rico, and all states of the United States except New York.

2. GWL&A is wholly-owned by The Great-West Life Assurance Company, which is a subsidiary of Great-West Lifeco Inc., an insurance holding company. Great-West Lifeco Inc. is a subsidiary of Power Financial Corporation of Canada, which is controlled by Power Corporation of Canada.

3. The Separate Account, established by GWL&A pursuant to Kansas law, is registered with the Commission as a unit investment trust. The Separate Account acts a funding vehicle for certain group variable flexible premium deferred annuity contracts (''Contracts''). The Separate Account currently has seventeen investment divisions, each of which invests exclusively in one of the corresponding portfolios of three open-end management investment companies.

4. BCE, the principal underwriter of the Contracts, is registered as a broker-dealer pursuant to the Securities Exchange Act of 1934, and is a member of the National Association of Securities Dealers, Inc.

5. The Contracts expressly reserve the right of GWL&A, both on its own behalf and on behalf of the Separate Account, to eliminate investment divisions, combine two or more investment divisions, or substitute one or more underlying funds for others in which its investment divisions are invested.

6. GWL&A, on its own behalf and on behalf of the Separate Account, proposes to substitute shares of the Maxim Series Fund Maxim INVESCO Balanced Portfolio (''Substituted Portfolio''), for shares of the Maxim Series Fund Total Return Portolio and the TCI Balanced Portfolio (''Eliminated Portfolios'') (the ''Substitution''). Applicants represent that the Substitution will benefit the participants by eliminating two portfolios with below average historical returns and consolidating participants' investments in the Substituted Portfolio, which has investment objectives similar to the Eliminated Portfolios.

7. Participants will be advised that they can transfer their shares in the Eliminated Portfolios to the remaining portfolios of the Separate Account or leave their shares in the Eliminated Portfolios until the date of the Substitution. No Eliminated Portfolio will accept additional premium payments (*i.e.*, new money or transfers) on or after the date of the Substitution. No sales load deductions or transfer charges will be assessed in connection with any transfers among the portfolios because of the Substitution.

8. Applicants represent that the total expenses of the Substituted Portfolio currently are 1.00%, which are greater than those of the Maxim Series Fund Total Return Portfolio, the total expenses of which are .60%, but the same as the total expenses of the TCI Balanced Portfolio.

Applicants' Legal Analysis

1. Section 26(b) of the 1940 Act provides that it shall be unlawful for any depositor or trustee of a registered unit investment trust holding the security of a single issuer to substitute another security for such security unless the Commission shall have approved such substitution. The Commission shall issue an order approving such substitution if the evidence establishes that it is consistent with the protection of investors and the purposes fairly intended by the policies and provisions of the 1940 Act. Section 26(b) protects the expectation of investors that the unit investment trust will accumulate shares of a particular issuer and is intended to insure that unnecessary or burdensome sales loads, additional reinvestment costs, other charges will not be incurred due to unapproved substitutions of securities.

2. Applicants request an order pursuant to Section 26(b) of the 1940 Act approving the Substitution. Applicants represent that the purposes, terms, and conditions of the Substitution are consistent with Section 26(b). Applicants believe the Substitution will benefit the participants by eliminating two portfolios with below average historical returns. Applicants represent that the Maxim Series Fund Total Return Portfolio, when compared to funds in its asset class, has performed below average for at least five quarters. In addition, its one, three, and five year returns of 10.62%, 8.65%, and 10.40% have been below average compared to funds within the same asset class. Applicants represent that the same is true of the TCI Balanced Portfolio which, when compared to other balanced funds, has been performing poorly for at least seven quarters. In addition, its one, three, and five year returns of 10.65%, 9.42%, and 9.08% also are below the average of balanced funds. GWL&A proposes to consolidate participants' investments in the Substituted Portfolio, which has similar investment objectives to the Eliminated Portfolios. The Substitution will remove poorly performing portfolios from the Separate Account while the similarity in investment objectives provides a means for Contract owners and/or all participants to continue their current investment goals and risk expectations.

3. Applicants represent that the Substitution will be effected at net asset value in conformity with Section 22(c) and 22(g) of the 1940 Act and Rule 22c–1 thereunder. The Substitution may be effected primarily for cash, but also may involve partial redemptions in-kind of securities (''Related Transactions''). The use of in-kind redemptions in conformity with Section 22(g) of the 1940 Act would alleviate the impact of the brokerage fees and expenses upon GWL&A or the investment adviser or sub-adviser of the Substituted Portfolio, as these entities will bear all expenses related to the Substitution. The Related Transactions will be effected to the extent consistent with the investment objectives and any applicable diversification requirements.

4. GWL&A or the investment adviser of the Substituted Portfolio will assume the transfer and custodial expenses and legal and accounting fees incurred with respect to the Substitution. Participants will not incur any fees or charges as a result of the transfer of account values from any portfolio. Applicants represent that there will be no increase in the Contract or Separate Account fees and charges after the Substitution. Applicants further represent that the Substitution is designed to avoid any adverse federal tax impact to the Contract owners or participants.

5. Section 6(c) of the 1940 Act authorizes the Commission to exempt any person, security, or transaction for any class or classes of persons, securities, or transactions from the provisions of the 1940 Act, if and to the extent that such exemption is necessary or appropriate in the public interest and consistent with the protection of investors and purposes fairly intended by the policy and provisions of the 1940 Act.

6. Section 17(a)(1) of the 1940 Act prohibits any affiliated person, or an affiliate of an affiliated person, of a registered investment company, from selling any security or other property to such registered investment company. Section 17(a)(2) of the 1940 Act prohibits any affiliated person from purchasing any security or other property from such registered investment company.

7. Section 17(b) of the 1940 Act authorizes the Commission to issue an order exempting a proposed transaction from Section 17(a) if: (a) The terms of the proposed transaction are fair and reasonable and do not involve overreaching on the part of any person concerned; (b) the proposed transaction is consistent with the policy of each registered investment company concerned; and (c) the proposed transaction is consistent with the general purposes of the 1940 Act.

8. Applicants request an order pursuant to Sections 6(c) and 17(b) of the 1940 Act exempting the Related Transactions from the provisions of Sections 17(a) of the 1940 Act.

9. Applicants represent that the terms of the Substitution are reasonable and fair and do not involve overreaching on the part of any person concerned. The Substitution will be effected at the net asset value of the securities involved and the interests of Contract owners will not be diluted. In-kind redemptions will alleviate some of the expenses involved with the Substitution and only will be used to the extent they are consistent with the investment objectives and applicable diversification requirements of the affected portfolios.

10. The Applicants represent that the Substitution and the Related Transactions are consistent with the policies of each investment company involved and the general purposes of the 1940 Act, and comply with the requirements of both Section 6(c) and 17(b).

Conclusion

Applicants assert that, for the reasons summarized above, the requested order approving the Substitution and Related Transactions should be granted.

For the Commission, by the Division of Investment Management, pursuant to delegated authority.

Margaret H. McFarland,

Deputy Secretary.

[FR Doc. 97–6473 Filed 3–13–97; 8:45 am]

BILLING CODE 8010–01–M

Sunshine Act Meeting

Time Change/Agency Meeting

The time for the closed meeting, scheduled for Tuesday, March 11, 1997, at 10:00 a.m., has been changed to 4:00 p.m. (previously announced in 62 FR 10303, March 6, 1997).

Notice is hereby given, pursuant to the provisions of the Government in the Sunshine Act, Pub. L. 94–409, that the Securities and Exchange Commission will hold the following closed meeting during the week of March 17, 1997.

A closed meeting will be held on Wednesday, March 19, 1997, at 10:00 a.m.

Commissioners, Counsel to the Commissioners, the Secretary to the Commission, and recording secretaries will attend the closed meeting. Certain staff members who have an interest in the matters may also be present.

The General Counsel of the Commission, or his designee, has certified that, in his opinion, one or more of the exemptions set forth in 5 U.S.C. 552b(c) (4), (8), (9)(A) and (10) and 17 CFR 200.402(a) (4), (8), (9)(i) and (10), permit consideration of the scheduled matters at the closed meeting.

Commissioner Hunt, as duty officer, voted to consider the items listed for the closed meeting in a closed session.

The subject matter of the closed meeting scheduled for Wednesday, March 19, 1997, at 10:00 a.m., will be:

Institution and settlement of injunctive actions.

Institution and settlement of administrative proceedings of an enforcement nature.

Opinions.

At times, changes in Commission priorities require alternations in the scheduling of meeting items. For further information and to ascertain what, if any, matters have been added, deleted or postponed, please contact:

The Office of the Secretary at (202) 942–7070.

Dated: March 11, 1997.

Jonathan G. Katz,

Secretary.

[FR Doc. 97–6650 Filed 3–12–97; 1:07 pm]

BILLING CODE 8010–01–M

[Release No. 34–38371; File No. SR–CHX–97–04]

Self-Regulatory Organizations; Notice of Filing and Immediate Effectiveness of Proposed Rule Change by the Chicago Stock Exchange, Incorporated Relating to SEC Transaction Fees

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (the ''Act''), 15 U.S.C. 78s(b)(1), notice is hereby given that on February 18, 1997, the Chicago Stock Exchange, Incorporated (''CHX'' or ''Exchange'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I, II, and III below, which Items have been prepared by the Exchange. The CHX has designated this proposal as one constituting a change to a due, fee, or other charge under Section 19(b)(3)(A) of the Act, which renders the rule effective upon receipt of this filing. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organizations Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to codify in its fee schedule the CHX's collection of SEC transaction fees assessed pursuant to Section 31 of the Act,[1] as authorized by CHX Article XV, Rule 4.

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 CHX included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statement may be examined at the places specified in Item IV below. The self-regulatory organization 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

Congress recently enacted the National Securities Markets Improvement Act of 1996 (''Improvement Act'') and the Omnibus Consolidated Appropriations Act for Fiscal Year 1997 (''Appropriations Act''), which together require national securities associations to pay SEC transaction fees for transactions in certain OTC securities.

As a result of the Improvement Act and Appropriations Act, the SEC has amended Rule 31–1 [2] to eliminate the current exemption from SEC transaction fees for transactions in OTC securities occurring on the CHX (as a national securities exchange) that are either listed on the CHX or are traded on the CHX pursuant to unlisted trading privileges (''OTC/UTP Securities''). Thus, effective January 1, 1997, the CHX is required to pay to the Commission a transaction fee for sales of OTC/UTP Securities transacted on the CHX.[3] Additionally, pursuant to the Improvement Act, effective October 1, 1997, these fees, as well as the traditional SEC transaction fees on exchange-registered securities that are not OTC/UTP Securities, will become payable to the SEC twice a year, as opposed to once a year as required by existing Section 31 of the Act.

The purpose of the proposed rule change is to codify the imposition of SEC transaction fees in the Exchange's fee schedule.

[1] 15 U.S.C. 78ee.

[2] 17 CFR 240.31–1.

[3] *See* Securities Exchange Act Release No. 38073 (December 23, 1996), 61 FR 68590 (December 30, 1996).

2. Statutory Basis

The CHX believes that the proposed rule change is consistent with Section 6(b)(4) of the Act [4] in that it provides for the equitable allocation of reasonable dues, fees and other charges among its members and issuers and persons using its facilities.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any inappropriate burden on competition.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants or Others

No written comments were solicited or received with respect to the proposed rule change.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing rule change establishes or changes a due, fee, or other charge imposed by the Exchange and therefore has become effective pursuant to Section 19(b)(3)(A) of the Act and subparagraph (e) of Rule 19b–4 thereunder. At any time within 60 days of the filing of such 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.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views and arguments concerning the foregoing. Persons making written submission should file six copies thereof with the Secretary, Securities and Exchange Commission, 450 Fifth Street, N.W., Washington D.C. 20549. 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, 450 Fifth Street, N.W., Washington D.C. Copies of such filing also will be available for inspection and copying at the Exchange. All submissions should refer to file number SR–CHX–97–04 and should be submitted by April 4, 1997.

[4] 15 U.S.C. 78f(b)(4).

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[5]

Margaret H. McFarland,

Deputy Secretary.

[FR Doc. 97–6419 Filed 3–13–97; 8:45 am]

BILLING CODE 8010–01–M

SOCIAL SECURITY ADMINISTRATION

Agency Information Collection Activities; Proposed Collection Requests and Submissions for OMB Review

This notice lists information collection packages that will require submission to the Office of Management and Budget as well as information collection packages submitted to the Office of Management and Budget for clearance.

I. The Social Security Administration publishes a list of information collection packages that will require submission to the Office of Management and Budget (OMB) for clearance in compliance with Public Law 104–13 effective October 1, 1995, The Paperwork Reduction Act of 1995. The information collection(s) listed below requires extension of the current OMB approval(s):

1. 0960–0462—You Can Make Your Payments by Credit Cards. The information on Forms SSA–4588 & SSA–4589 will be used to update the individual's social security record to reflect that a payment has been made on their overpayment and to effectuate payment through the appropriate credit card company.

Number of Respondents: 12,000.

Frequency of Response: 1.

Average Burden Per Response: 5 minutes.

Estimated Annual Burden: 1,000 hours.

2. 0960–0323—Third Party Liability Information Statement. Form SSA–8019 is used by the Social Security Administration to gather information or to make changes in existing information about third party insurance (other than Medicare or Medicaid), which could be responsible for payment for a beneficiary's medical care.

Number of Respondents: 65,400.

Frequency of Response: 1.

Average Burden Per Response: 5 minutes.

[5] 17 CFR 200.30–3(a)(12).

Estimated Annual Burden: 5,450 hours.

3. 0960–0068—Representative Payee Report. Sections 205(j) and 1631(a)(2) of the Social Security Act provide for the payment of supplemental social security benefits to a relative, another person or an organization when the best interests of the beneficiary will be served. Form SSA–6230 (20 CFR 404.2065) is sent to parents, stepparents and grandparents with custody of minor children receiving social security benefits. Form SSA–623 (20 CFR 404.2065 and 416.665) is sent to all other payees with or without custody of the beneficiary. Both forms are used to determine the continuing suitability of the individual/organization to serve as representative payee.

Number of Respondents: 5,315,160.
Frequency of Response: 1.
Average Burden Per Response: 15 minutes.
Estimated Annual Burden: 1,328,790 hours.

4. Telephone Replacement Card Pilot Test—0960–NEW. The Social Security Administration will conduct a pilot study on obtaining information by telephone from individuals who need a duplicate Social Security Number (SSN) card. The information will be used to properly identify an individual prior to releasing a replacement SSN card, thus eliminating the need for the respondent to take or mail his/her identify documents to a Social Security office. The information provided, which should be known by the true Social Security number holder, will be compared to information available in our current electronic systems. The respondents are individuals in the pilot study who request a duplicate SSN replacement card by telephone.

Number of Respondents: 500,000.
Frequency of Response: 1.
Average Burden Per Response: 2 minutes.
Estimated Annual Burden: 16,667 hours.

To receive a copy of the form(s) or clearance package(s), call the SSA Reports Clearance Officer on (410) 965–4123 or write to her at the address listed below the information collection(s). Written comments and recommendations regarding the information collection(s) should be sent within 60 days from the date of this publication, directly to the SSA Reports Clearance Officer at the following address: Social Security Administration, DCFAM, Attn: Judith T. Hasche, 6401 Security Blvd., 1–A–21 Operations Bldg., Baltimore, MD 21235.

In addition to your comments on the accuracy of the agency's burden estimate, we are soliciting comments on 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.

II. The Social Security Administration publishes a list of information collection packages submitted to the Office of Management and Budget (OMB) for clearance in compliance with Public Law 104–13 effective October 1, 1995, The Paperwork Reduction Act of 1995. The information collections listed below have been submitted to OMB:

1. Claimant's Medications—0960–0289. The information on form HA–4632 is used by the Social Security Administration to compile a current list of medications used by a claimant. The list is provided to an Administrative Law Judge (ALJ), who is considering the disability aspects of the claim. The affected public consists of claimants for disability benefits, who have requested a hearing before an ALJ.

Number of Respondents: 227,107.
Frequency of Response: 1.
Average Burden Per Response: 15 minutes.
Estimated Annual Burden: 56,777 hours.

2. Request for SSI Benefit Estimate—0960–0492. The Social Security Administration collects the information on Form SSA–3716 for the sole purpose of complying with an SSI recipient's request for an estimate of the impact of his/her work on the receipt of SSI benefits.

Number of Respondents: 50,000.
Frequency of Response: 1.
Average Burden Per Response: 5 minutes.
Estimated Annual Burden: 4,167 hours.

3. Statement of Employer—0960–0030. The information collected on Form SSA–7011 is used by the Social Security Administration to substantiate allegations of wages paid to workers when those wages do not appear in SSA's records of earnings, and the worker does not have proof of payment. This information is used to process claims for social security benefits and to resolve discrepancies in earnings records. The respondents are certain employers who can verify allegations of wages made by the wage earner.

Number of Respondents: 925,000.
Frequency of Response: 1.
Average Burden Per Response: 20 minutes.
Estimated Annual Burden: 308,333 hours.

4. Supplemental Security Income Notice of Interim Assistance Reimbursement (two forms). Forms SSA–8125 0960–0546 and SSA–L8125 0960–0563 collect interim assistance reimbursement (IAR) information from States which provide such assistance. Form SSA–8125 is used in most situations where IAR is applicable. Form SSA–L8125 is used in situations where an individual entitled to underpayments has received IAR from a State and his/her benefit will be controlled by SSA through the installment process. The respondents are states which provide IAR to SSI claimants.

	SSA–8125	SSA–L8125
Number of Respondents.	80,000	60,000.
Frequency of Response.	1	1.
Average Burden Per Response.	10 minutes	10 minutes.
Estimated Annual Burden.	13,333 hours	10,000 hours.

5. Work Reintegration Study—0960–0543. The purpose of the Work Reintegration Study is to identify those incentives and interventions that are most successful in assisting persons who are disabled due to a back condition to return to work. The information collected will be used primarily to complete a cross-national analysis of this issue. Data also will be gathered on subjects of particular importance in the U.S. The findings will provide policymakers with information that will be highly useful in establishing disability policy. The respondents are persons entitled to Social Security Disability Insurance, Supplemental Security Income (SSI) or State Temporary Disability Insurance.

Number of Respondents: 800.
Frequency of Response: 1.
Average Burden Per Response: 1 hour.
Estimated Annual Burden: 800 hours.

6. Personal Earnings and Benefit Estimate Statement (PEBES)—Identity Verification Survey—0960–NEW. The Social Security Administration (SSA) is conducting a survey to verify the identity and address of individuals who request their PEBES by means of the Form SSA–7004–SM, Request for Earnings and Benefit Statement and through the Internet. The information is needed to determine the number of invalid requests for PEBES using the SSA–7004–SM compared to the number of invalid PEBES requests using the Internet. The information will be used in the evaluation of whether to adopt the Internet as an appropriate vehicle to

obtain PEBES requests. The respondents are a sample of PEBES requestors whose identity and address could not be verified through other means.

Number of Respondents: 300.

Frequency of Response: 1.

Average Burden Per Response: 5 minutes.

Estimated Annual Burden: 25 hours.

To receive a copy of the form or clearance packages, call the SSA Reports Clearance Officer on (410) 965–4123 or write to her at the address listed below. Written comments and recommendations regarding the information collection(s) should be directed within 30 days to the OMB Desk Officer and SSA Reports Clearance Officer at the following addresses:

(OMB)—Office of Management and Budget, OIRA, Attn: Laura Oliven, New Executive Office Building, Room 10230, 725 17th St., NW., Washington, D.C. 20503

(SSA)—Social Security Administration, DCFAM, Attn: Judith T. Hasche, 1–A–21 Operations Bldg., 6401 Security Blvd., Baltimore, MD 21235.

Dated: March 6, 1997.

Judith T. Hasche,

Reports Clearance Officer, Social Security Administration.

[FR Doc. 97–6240 Filed 3–13–97; 8:45 am]

BILLING CODE 4190–29–P

Testing Modifications to the Disability Determination Procedures; Single Decisionmaker Model Test Site Continuation

AGENCY: Social Security Administration.

ACTION: Notice of the continuation of a test site and the duration of the test involving a single decisionmaker.

SUMMARY: The Social Security Administration is announcing the continuation of a test that it has been conducting under the final rules published in the Federal Register on April 24, 1995 (60 FR 20023), as well as the location and duration of that test. Those final rules authorize the testing of several modifications to the disability determination procedures that we normally follow in adjudicating claims for disability insurance benefits under title II of the Social Security Act (the Act) and claims for supplemental security income (SSI) payments based on disability under title XVI of the Act. This notice announces the continuation of the test involving the use of a single decisionmaker who may make the disability determination without requiring the signature of a medical consultant. This notice also announces the designated test site and the duration of the test.

FOR FURTHER INFORMATION CONTACT: Harry Pippin, Models Team Leader, Office of Disability, Disability Process Redesign Staff, Social Security Administration, 6401 Security Boulevard, Baltimore, Maryland 21235, 410–965–9203.

SUPPLEMENTARY INFORMATION: On April 24, 1995, we published final rules in the Federal Register authorizing us to test different modifications to the disability determination procedures. The tests are designed to provide us with information so that we can determine the effectiveness of the concepts in the models in improving the disability process.

Under this test, a single decisionmaker may make disability determinations without generally requiring a medical consultant to sign the disability determination forms that we use to certify the determination. On May 3, 1996, we announced in the Federal Register our intent to begin tests, on or about May 1, 1996, of the procedures to be conducted by a single decisionmaker (61 FR 19969). We also explained that we would select cases for the evaluation for approximately six months and might continue to process cases for another six months. In that announcement, we identified nine test sites in seven states. We are now planning additional testing of the single decisionmaker model; and at this time, we are announcing a continuation of testing at one site. We plan to continue testing the single decisionmaker model on or about February 24, 1997. We will continue the test for approximately fourteen months. We will publish another notice in the Federal Register if we extend the duration of the test. Continued testing of the single decisionmaker model will be conducted at the following location:

• North Carolina Division of Social Services, Disability Determination Services, 321 Chapanoke Road, Raleigh, NC 27603.

Not all cases received in the test site listed above will be handled under the test procedures. However, if a claim is selected to be handled by a single decisionmaker as part of the test, the claim will be processed under the procedures established under the final rules cited above.

Carolyn W. Colvin,

Deputy Commissioner for Programs and Policy.

[FR Doc. 97–6408 Filed 3–13–97; 8:45 am]

BILLING CODE 4190–29–P

OFFICE OF THE UNITED STATES TRADE REPRESENTATIVE

[Docket No. 301–111]

Initiation of Section 302 Investigation and Request for Public Comment: Certain Subsidies Affecting Access to the European Communities' Market for Modified Starch

AGENCY: Office of the United Trade Representative.

ACTION: Notice of initiation of investigation; request for written comment.

SUMMARY: The Acting United States Trade Representative (Acting USTR) has initiated an investigation under section 302(a) of the Trade Act of 1974 (the Trade Act) with respect to certain acts, policies and practices of the European Communities (EC), more specifically, the provision of subsides that affect access to the EC modified starch market. The Acting USTR invites written comments from the public on the matters being investigated and the determinations to be made under section 304 of the Trade Act.

DATES: This investigation was initiated on March 8, 1997. Written comments from the public are due on or before noon on Monday, April 14, 1997.

ADDRESSES: Office of the United States Trade Representative, 600 17th Street, NW., Washington, D.C. 20508.

FOR FURTHER INFORMATION CONTACT: Ronald K. Lorentzen, Office of WTO and Multilateral Affairs, (202) 395–3063; Audrey Winter, Office of the General Counsel, (202) 395–7305; or Marilyn Moore, Office of Agricultural Affairs, (202) 395–6127.

SUPPLEMENTARY INFORMATION: On January 22, 1997, the U.S. Wheat Gluten Industry Council filed a petition pursuant to section 302(a) of the Trade Act (19 U.S.C. 2412(a)) alleging that certain subsidy schemes of the EC constitute acts, policies and practices that violate, or are inconsistent with and otherwise deny benefits to the United States under, the General Agreement on Tariffs and Trade 1994 (GATT) and the Agreement on Subsidies and Countervailing Measures (SCM Agreement). In particular, the petition alleges that four EC subsidy programs ((1) the wheat export tax; (2) the starch production refund program; (3) the starch export restitution program; and (4) various quotas and other productions limits on other starches) violate EC obligations, cause serious prejudice to U.S. interests and nullify or impair U.S. benefits under the World Trade Organization (WTO) agreements insofar as they directly or indirectly benefit EC production and export of wheat gluten to the United States and, in the case of the wheat export tax and the starch production refund program, displace or impede imports of modified starch from the United States to the EC. The petition also states that numerous other subsidy programs available within individual EC Member States may have benefited the production of wheat starch by EC producers.

Investigation and Consultation

The Acting USTR has reviewed the allegation in the petition and has serious concerns about difficulties facing the U.S. wheat gluten and wheat starch industries. Accordingly, on March 8, 1997, the Acting USTR determined to initiate an investigation under section 302 with respect to the EC starch production refund program to determine whether subsidies granted under that program are causing or threatening to cause serious prejudice to U.S. interests with respect to U.S. exports of modified starch to the EC, or are nullifying or impairing benefits accruing to the United States under the WTO agreements. With respect to the other allegations in the petition regarding subsidized imports of EU wheat gluten into the United States, the Acting USTR has invited the petitioners to consider seeking additional information through the procedures provided for in section 308 of the Trade Act and USTR is prepared to continue working with them in the development of information and analysis which may form the basis for further action. Insofar as other U.S. trade laws are designed specifically to address the problems of increased and/or unfairly traded imports into the U.S. market, the Acting USTR noted that the petitioners may wish to explore more fully these other avenues of relief. The Acting USTR also intends to continue to pursue consultations with the EU regarding its wheat gluten exports to the United States, pursuant to a bilateral agreement with the EU on grains signed on July 22, 1996. In light of the foregoing, the Acting USTR decided at this juncture not to initiate an investigation under Section 302 with respect to these other allegations in the petition.

Pursuant to section 303(b)(1)(A) of the Trade Act, the Acting USTR has decided to delay requesting consultations with the EC, required under section 303, on the EC starch production refund program for up to 90 days for the purpose of verifying and improving the petition to ensure an adequate basis for consultations with the EC.

Public Comment: Requirements for Submissions

Interested persons are invited to submit written comments concerning the acts, policies and practices of the EC which are the subject of this investigation, the amount of burden or restriction on U.S. commerce caused by these acts, policies and practices, and the determinations required under section 304 of the Trade Act. Comments must be filed in accordance with the requirements set forth in 15 CFR 2006.8(b) (55 FR 20593) and must be filed on or before noon on Monday, April 14, 1997. Comments must be in English and provided in twenty copies to: Sybia Harrison, Staff Assistant to the Section 301 Committee, Room 223, Office of the U.S. Trade Representative, 600 17th Street, NW, Washington, D.C. 20508.

Comments will be placed in a file (Docket 301–111) open to public inspection pursuant to 15 CFR 2006.13, except confidential business information exempt from public inspection in accordance with 15 CFR 2006.15. Confidential business information submitted in accordance with 15 CFR 2006.15 must be clearly marked ‘‘BUSINESS CONFIDENTIAL’’ in a contrasting color ink at the top of each page on each of 20 copies, and must be accompanied by a nonconfidential summary of the confidential information. The nonconfidential summary shall be placed in the file that is open to public inspection. Copies of the public version of the petition and other relevant documents are available for public inspection in the USTR Reading Room. An appointment to review the docket (Docket No. 301–111) may be made by calling Brenda Webb (202) 395–6186. The USTR Reading Room is open to the public from 9:30 a.m. to 12 noon and 1:00 p.m. to 4:00 p.m., Monday through Friday, and is located in Room 101.

Irving A. Williamson,

Chairman, Section 301 Committee.

[FR Doc. 97–6513 Filed 3–13–97; 8:45 am]

BILLING CODE 3190–01–M

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

Research, Engineering and Development (R,E&D) Advisory Committee

Pursuant to section 10(A)(2) of the Federal Advisory Committee Act (Pub. L. 92–463; 5 U.S.C. App. 2), notice is hereby given of a meeting of the FAA Research, Engineering and Development Advisory Committee. The meeting will be held on April 8–9, 1997 at the Maritime Institute of Technology, 5700 Hammonds Ferry Road, Linthicum Heights, Maryland.

On Tuesday, April 8, 1997 the meeting will begin at 8:00 a.m. and end at 5:00 p.m. On Wednesday, April 9, 1997, the meeting will begin at 8:00 a.m. and end at 5:00 p.m. The meeting agenda will review the Federal Aviation Administration planned fiscal year 1999 research and development investments in the areas of air traffic services, airports, aircraft safety, security, human factors and environment and energy.

Attendance is open to the interested public but limited to space available. Persons wishing to attend the meeting or obtain information should contact Lee Olson at the Federal Aviation Administration, AAR–200, 800 Independence Avenue, SW, Washington, DC 20591 (202) 267–7358.

Members of the public may present a written statement to the Committee at any time.

Issued in Washington, DC on March 10, 1997.

Andres G. Zellweger,

Director, Office of Aviation Research.

[FR Doc. 97–6526 Filed 3–13–97; 8:45 am]

BILLING CODE 4910–13–M

Notice of Intent To Rule on Application To Use the Revenue From a Passenger Facility Charge (PFC) at New Hanover International Airport, Wilmington, NC

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of intent to rule on application.

SUMMARY: The FAA proposes to rule and invites public comment on the application to use the revenue from a PFC at New Hanover International Airport under the provisions of the Aviation Safety and Capacity Expansion Act of 1990 (Title IX of the Omnibus Budget Reconciliation Act of 1990) (Pub. L 101–508) and Part 158 of the Federal Aviation Regulations (14 CFR Part 158).

DATES: Comments must be received on or before April 14, 1997.

ADDRESSES: Comments on this application may be mailed or delivered in triplicate to the FAA at the following address: Atlanta Airports District Office, Campus Building, 1701 Columbia Avenue, Suite 2–260, College Park, GA 30337–2747.

In addition, one copy of any comments submitted to the FAA must be mailed or delivered to Mr. Robert J. Kemp, New Hanover County Airport Authority at the following address: Mr. Robert J. Kemp, Airport Director, New Hanover County Airport Authority, 1740 Airport Boulevard, Wilmington, NC 28405.

Air carriers and foreign air carriers may submit copies of written comments previously provided to the New Hanover County Airport Authority under section 158.23 of Part 158.

FOR FURTHER INFORMATION CONTACT: Terry R. Washington, Program Manager, Atlanta Airports District Office, 1701 Columbia Avenue, Suite 2–260, College Park, GA 30337–2747, Telephone No. (404) 305–7143.

The application may be reviewed in person at this same location.

SUPPLEMENTARY INFORMATION: The FAA proposes to rule and invites public comment on the application to use the revenue from a PFC at New Hanover International Airport under the provisions of the Aviation Safety and Capacity Expansion Act of 1990 (Title IX of the Omnibus Budget Reconciliation Act of 1990) (Pub. L. 101–508) and Part 158 of the Federal Aviation Regulations (14 CFR Part 158).

On February 27, 1997, the FAA determined that the application to use the revenue from a PFC submitted by New Hanover County Airport Authority was substantially complete within the requirements of section 158.25 of Part 158. The FAA will approve or disapprove the application, in whole or in part, no later than May 28, 1997.

The following is a brief overview of the application.

Level of the proposed PFC: $3.00.

Charge effective date: February 1, 1994.

Charge expiration date: January 31, 1997.

Total PFC revenue collected: $410,546.

Application number: 97–02–U–00–ILM.

Brief description of proposed project(s):

1. Medium Intensity Taxiway Lighting Rehabilitation
2. Acquire Ramp Sweeper
3. Precision Path Indicator Runway 35
4. Reconstruct/Widen Taxiways A&H, and Construct Exit Taxiways for Runway 6–24
5. Install fencing & Security Road

Class or classes of air carriers which the public agency did not require to collect PFCs: On demand air taxi/commercial operator filing FAA form 18–31 enplaning less than 150 passengers per year at New Hanover International Airport.

Any person may inspect the application in person at the FAA office listed above under **FOR FURTHER INFORMATION CONTACT.** In addition, any person may, upon request, inspect the application, notice and other documents germane to the application in person at the New Hanover County Airport Authority.

Issued in Atlanta, Georgia on March 7, 1997.

Dell T. Jernigan,

Manager, Atlanta Airports District Office Southern Region.

[FR Doc. 97–6527 Filed 3–13–97; 8:45 am]

BILLING CODE 4910–13–M

Federal Transit Administration

Policy on Transit Joint Development

AGENCY: Federal Transit Administration (FTA), U.S. Department of Transportation.

SUMMARY: FTA is revising and clarifying its Joint Development policies with respect to program income in relation to real estate acquired with funds under Federal transit law, 49 U.S.C. 5301 et seq. This Notice supplements the guidance contained in Appendix B of FTA Circular 9300.1 ''Joint Development Projects.'' All joint development projects undertaken in conformance with this policy will be considered ''mass transportation projects'' eligible for funding under FTA capital programs. This policy is applicable to development of properties acquired under previous grants as well as new grants, as specified in the FTA Master Agreement dated October 1, 1996. All such projects must generate a one-time payment or revenue stream for transit use, the present value of which equals or exceeds the fair market value of the property. In determining the fair market value, FTA will consider appraisal methods which factor in the ''highest and best transit use'' of the property as defined in the body of this notice. Where the grantee retains continuing control and use of the joint development for mass transportation purposes, all proceeds will be considered program income. Proposals that meet the criteria described below may be submitted at any time to the appropriate FTA regional office, listed in Attachment A.

DATES: Effective March 14, 1997.

FOR FURTHER INFORMATION CONTACT: Richard Steinmann, Director, Office of Policy Development, on (202) 366–4060; or Paul Marx, Economist, on (202) 366–1675.

SUPPLEMENTARY INFORMATION:

Introduction

Transit systems have long been encouraged to undertake joint development projects in connection with their rail transit stations. However, apparent inconsistencies between transit laws, the Common Grant Rule and FTA policy may have dissuaded some transit authorities from initiating joint development projects. This notice clarifies the relationship between transit laws and regulations and FTA policy regarding property disposition, leases of property, and sale of property for joint development. This FTA policy statement affects primarily the treatment of program income with regard to joint development and the definition of ''highest and best transit use'' in joint development.

Transit systems are permitted in 49 U.S.C. 5309 (a)(1)—(5) and (7) [former Section 3(a)(1)(D) of the Federal Transit Act] to use grant funds to also support ''transportation projects which enhance the effectiveness of any mass transportation project and are physically or functionally related to such mass transportation project or which create new or enhanced coordination between public transportation and other forms of transportation, either of which enhance urban economic development or incorporate private investment including commercial and residential development.'' The Intermodal Surface Transportation Efficiency Act of 1991 (ISTEA) added Section 3 (a)(1)(F), now codified at 49 U.S.C. 5309(a)(7), to the Federal transit laws. This section allows FTA grant funds to support any ''other nonvehicular capital improvements that the Secretary may decide would result in increased mass transportation usage in the corridor.''

FTA is encouraging transit systems to undertake transit-oriented Joint Development projects either under new grants or with property acquired under previous grants, whether the property is associated with a rail, bus or other transit facility. The purpose of this Joint Development should be both to secure a revenue stream for the transit system and to help shape the community that is being served by the transit system. Where the grantee retains effective continuing control over the joint development for mass transportation purposes (such as an easement, or a contractual arrangement), all proceeds of sale, lease or other incumbrance of the property will be treated as program income for use by the transit system to meet capital and operating needs. This is a departure from previous policy in two areas. First, FTA will now define all revenue derived from such joint development to be program income as defined in the Common Grant Rule at 49 CFR, Subtitle A, § 18.25. Second, grantees may use the new concept of ''highest and best transit use'', as an alternate to ''highest and best use'', in valuing real property for transit-oriented joint development. To accomplish this change, the FTA Master Agreement has been expressly modified to include joint development as an eligible activity in all capital grants to which it applies. Further, grantees may request amendment of grants issued prior to FY 1997, as desired, to expressly include joint development within the scope of such grants.

In accordance with this new policy, transit agencies have three options: they can sell property as excess for non-transit use; they can lease the property for incidental, non-interfering use by others while the property is held for a future identified transit use; or they can undertake a transit-oriented joint development on the property. In the case of a sale without a continuing transit use, property disposition rules under the Common Grant Rule at 49 CFR, Subtitle A, § 18.31 apply. That is, the pro-rata Federal share of the net proceeds of a sale at fair market value are returned to the U.S. Treasury.

Transit-oriented joint development can be accomplished through a sale or lease of federally funded property, or through direct participation of the transit agency in the development e.g., as a general partner, depending upon the needs of the project. To qualify as a ''transportation project'', the transit agency must retain sufficient continuing control over the property to ensure its continued physical or functional relationship to transit. [1] This control may be exerted through any number of legally enforceable contractual arrangements, ranging from a simple easement to ensure unimpeded access between the development and the transit factility by transit patrons, or perhaps some form of reverter clause to take effect in the event access becomes unreasonably curtailed. Any legally enforceable arrangement between the transit system and the developer which preserves the defined physical or functional relationship between the development and the transit facility should satisfy this requirement. As long as such control is maintained, the transit agency may retain all revenues from such joint development as program income.

Policy: FTA encourages transit systems to undertake joint development projects at and around transit stations, bus terminals, intermodal facilities and other transit properties, where such projects are physically or functionally related to the provision of transit service, and where they increase transit revenues through proceeds from the joint development. FTA will do this by: making grants under the authority to support Joint Development provided by 49 U.S.C. 5307,[2] 5309 (a) (1)–(5), 5309 (a)(7), and 5309 (f), and by allowing the proceeds from sale, lease or other incumbrance of property for transit-oriented joint development to be retained by the transit system for transit operating and capital expenses.

FTA considers transit-oriented joint development already to be within the scope of nearly all capital grants involving real property unless expressly prohibited by a special term or condition of the grant. This is due to a term in most, if not all, capital grants requiring the grantee to follow FTA's most recent policies and procedures in administering its grants. Notwithstanding, FTA will modify existing grants at the request of the grantee, when this step is desired to expressly reflect transit-oriented joint development in the grant purpose. In the case of a section 5309 grant made between 1978 and 1983,[3] and certain section 5307 grants, FTA will review joint development proposals on a case-by-case basis, and will work with the grantee to achieve the purposes of this policy. The FTA Master Agreement dated October 1, 1996 expressly includes transit-oriented joint development as an authorized grant purpose.

This policy applies to projects funded under the following transit programs: Section 5309, Capital; Section 5307, Urbanized Area Formula; Section 5310, Elderly and Persons with Disabilities; and Section 5311, Nonurbanized Area Program.[4]

The policy will not affect leases of real property for non-transit purposes or disposition of property that is no longer needed for transit purposes.

Criteria

To be eligible for consideration as a transit-oriented joint development project under this policy, the project must have the following characteristics:

- It includes a transit element; *and*
- It enhances urban economic development or incorporates private investment including office, commercial, or residential development; *and*
- It enhances the effectiveness of a mass transit project, and the non-transit element is physically or functionally related to the mass transit project; *or*
- it creates new or enhanced coordination between public transit and other forms of transportation; *or*,
- it includes nonvehicular capital improvements that result in increased transit usage, in corridors supporting fixed guideway systems.

Financial criteria that FTA will use in assessing joint development projects using land acquired with FTA funds are as follows:

- It is FTA's intent that the transit system be able to negotiate its project benefit whenever possible, on the basis of the value added to the property by the planning, design and construction of transit-oriented joint development around the transit facility. Therefore the project shall generate either a one-time payment or a revenue stream, the present value of which equals either the current market value or the appraised value of the property, taking highest and best transit use into account.[5]
- When the joint development project is one of several being undertaken in a program of joint development projects, the combined revenue streams from all of the projects may be balanced against the cumulative appraised value of the combined real estate on a portfolio basis. In such an approach, one project could be carried forward at a nominal loss, provided other projects in the same portfolio produced a proportionally greater revenue for the transit system, resulting in a net present value benefit equal to the appraised value of the property used, taking highest and best transit use into account.
- As long as the grantee retains effective continuing control of the joint development project we do not consider this a disposition of property. Thus, the grantee may retain all revenues from the project as program income. However, if the grantee cedes effective continuing control of the property for transit

[1] Effective, continuing control of the property for transit purposes does not substitute for the grantee's obligation to ensure ongoing access by the general public to the transit facility.

[2] FTA has determined that joint development authority under section 5309(a) is coextensive with section 5307.

[3] Funding for certain grants may have lapsed which could prevent their reopening should a change in scope be necessary to carry out transit oriented joint development.

[4] FTA realizes that properties supported with Nonurbanized Area or Elderly and Persons with Disabilities program funds are unlikely candidates for joint development. However, FTA wishes to make it clear that the source of funding is not to be regarded as an impediment to a joint development proposal under this policy.

[5] The proposer must make a convincing case that the transit-oriented joint development will be more beneficial to the transit system than an outright sale of the property for non-transit purposes. For example, ''Highest and best transit use'' of a property for a day care center produces less income than ''highest and best use'' as a coin-operated laundry, but market sureveys show it would attract and serve a greater number of transit riders and is better suited to the overall plan for the area. This would be an appropriate trade-off.

use the grantee could be liable for repayment of the Federal share of the current market value of the property.

Local Supportive Actions

While the preceding criteria are mandatory, the following are factors that will directly affect the successful implementation of any transit-oriented joint development, and warrant consideration in a joint development proposal. To ensure a transit-supportive environment in the community served by the transit system, FTA encourages local governments, transportation agencies, employers, building owners and managers, and public and private developers to work together to implement policies and strategies that will support transit use in daily activities. Supportive land use policies include promoting mixed use and high density development around transit facilities. Urban design enhancements include landscaping, pedestrian and bicycle amenities, safety and security improvements, and improved access to transit services. Transportation management actions include parking management strategies to increase the cost and reduce the number of non-transit parking spaces for single occupant vehicles, priority treatment for transit vehicles, and transit pass programs. Also included would be activities that extend the hours of operation of transit facilities and thereby enhance the perception of safety in the surrounding areas.

Definitions

Joint Development

Joint development projects are commercial, residential, industrial, or mixed use developments that are undertaken in concert with transit facilities. They may include private, and non-profit development activities usually associated with fixed guideway (Rail or Busway) transit systems that are new or being modernized or extended. Joint development projects may also be associated with bus facilities, intermodal transfer facilities (e.g., bus to rail), transit malls, and Federal, State or local investments in local facilities (such as a bus terminal and tourist facility). FTA funds may be used to facilitate development that enhances transit; they may not be used for purely private development such as construction and permanent financing costs related to the design or construction of purely retail, residential, or other commercial public and private revenue-producing facilities.

Highest and Best Transit Use

The highest and best *transit* use is that combination of residential, retail, commercial and parking space that results in the highest level of transit support from a combination of project revenues and increased ridership. The term is intended to combine the concepts of highest and best use in real estate assessment with transit-oriented development. In some circumstances, the highest and best use for a property, i.e., that use resulting in the greatest cash price for the property, may not be transit-oriented. Secure storage for construction equipment, or a coin-operated car wash would be examples of non-transit-oriented developments. FTA does not intend to limit the local community's ability to define social or other benefits that it wishes to achieve through a transit-oriented development. Thus, locally preferred plans for ''highest and best transit use'' may be acceptable even if they do not generate the highest possible level of financial return. The Joint Development proposal will indicate the extent to which the highest and best transit use value varies from the traditional highest and best use assessment, and the basis for this variation.

Physically or Functionally Related

Each project must establish the link between transit and the proposed joint development project. Issues to be addressed should include travel time between the joint development and the transit facility, reasonable access between the development and the transit facility, trip generation rates of the proposed development, and the transit system's share of those trips. Functional relationships should not extend beyond the distance most people will reasonably walk to use a transit service—about 1,500 feet.

Revenue Stream

Research has shown that the siting and development of transit service adds to property values near transit stations, and that collocation of residential, commercial and retail establishments with the transit system enhances social and economic returns for the community. Therefore, a joint development project should be planned to generate revenue for the transit system from this added value. This revenue may take the form of a one-time cash payment for the sale of land, air rights, or some other form of property rights. Or it may be a revenue stream from an installment sale, lease, ground rent, or other compensation as agreed between the transit system and the developer, including but not limited to in-kind services such as construction or maintenance. The payment or revenue stream may be delayed for a time to support the project purpose, but the present value of all revenues must equal the current market value based on the highest and best transit use.

In the case of a program of joint development, conducted on a corridor or system wide level, FTA will evaluate the revenue stream on a portfolio basis, requiring that the sum of revenue streams for all developed properties be equal to the combined appraised value of the land used to generate the revenues, taking into account the highest and best transit use.[6] There may be instances where the transit system's participation in a joint development project adds value to that project above the value of the land itself. This additional value will allow the transit system to attract development at other, more ''difficult'' properties along the same corridor by making some revenue concessions on these properties.

As long as the grantee can demonstrate that it has the ability to retain effective continuing control of the joint development for transit use, i.e. its physical or functional relation to transit, it may retain any proceeds from the project as program income. However, if the grantee cedes effective control over the property for transit use it may be liable for reimbursement of the Federal interest in the property.

Procedures

Joint Development proposals that meet the criteria in this notice may be submitted at any time to the appropriate FTA regional office, listed in attachment A. They should include, at a minimum, the Joint Development agreement, a market and financial assessment of the Joint Development and its impact on the transit system, and a statement of the outcome of planning and coordination between the Joint Development and the transit facility. The proposal should document the projected benefits for the transit system as well as the effective continuing control of the Joint Development project for transit purposes, as outlined in the definition section above.

Authority: 49 U.S.C. 5307, 5309(a)(1)–(5), 5309(a)(7), and 5309(f), as well as 49 CFR Subtitle A.

[6] Within reason, the grantee may also postpone development of some properties along the corridor, to enhance their final development value. This should be declared in the joint development proposal.

Issued on March 10, 1997.

Gordon J. Linton,

Administrator.

Attachment A

Listing of FTA Regions:

Region 1

Volpe National Transportation Systems Center, Kendall Square, 55 Broadway, Suite 920, Cambridge, MA 02142–1093

Region 2

26 Federal Plaza, Suite 2940, New York, NY 10278–0194

Region 3

1760 Market Street, Suite 500, Philadelphia, PA 19103–4124

Region 4

Atlanta Federal Center, 100 Alabama Street, N.W., 17th Floor, Suite T1750, Atlanta, GA 30303

Region 5

55 East Monroe Street, Rm 1415, Chicago, IL 60603–5704

Region 6

Parkview Place, 524 East Lamar Street, Suite 175, Arlington, TX 76011–3900

Region 7

6301 Rockhill Road, Suite 303, Kansas City, MO 64131–1117

Region 8

Columbine Place, 216 16th Street, Suite 650, Denver, CO 80202–5120

Region 9

201 Mission Street, Suite 2210, San Francisco, CA 94105–1831

Region 10

Jackson Federal Building, 915 Second Ave., Suite 3142, Seattle, WA 98174–1002.

[FR Doc. 97–6462 Filed 3–13–97; 8:45 am]

BILLING CODE 4910–57–P

National Highway Traffic Safety Administration

[Docket No. 97–013; Notice 2]

General Motors Corporation; Receipt of Application for Decision of Inconsequential Noncompliance; Correction

AGENCY: National Highway Traffic Safety Administration, DOT.

ACTION: Correction to a notice.

SUMMARY: The Docket No. 97–113; Notice 1, as it appeared in the Federal Register on March 7, 1997, on page 10618 is incorrect. It should appear as Docket 97–013; Notice 1.

Authority: 49 U.S.C. 30118, 30120; delegation of authority at 49 CFR 1.50 and 501.8.

Issued: March 11, 1997.

L. Robert Shelton,

Associate Administrator for Safety Performance Standards.

[FR Doc. 97–6525 Filed 3–13–97; 8:45 am]

BILLING CODE 4910–59–M

DEPARTMENT OF THE TREASURY

Customs Service

[T.D. 97–16]

Country of Origin Marking of Products From the West Bank and Gaza

AGENCY: U.S. Customs Service, Department of the Treasury

ACTION: Notice of policy.

SUMMARY: This document clarifies T.D. 95–25 by notifying the public that, with respect to imported goods which are produced in the West Bank and Gaza Strip, acceptable country of origin markings consist of ''West Bank/Gaza,'' ''West Bank/Gaza Strip,'' ''West Bank and Gaza,'' and ''West Bank and Gaza Strip'' as well as ''West Bank,'' ''Gaza'' or ''Gaza Strip.''

EFFECTIVE DATE: The position set forth in this document is effective for merchandise entered or withdrawn from warehouse for consumption on or after March 14, 1997.

FOR FURTHER INFORMATION CONTACT: Craig Walker, Special Classification and Marking Branch (202) 482–6980.

SUPPLEMENTARY INFORMATION:

Background

Section 304 of the Tariff Act of 1930, as amended (19 U.S.C. 1304), provides that, unless excepted, every article of foreign origin (or its container) imported into the U.S. shall be marked in a conspicuous place as legibly, indelibly, and permanently as the nature of the article (or its container) will permit, in such a manner as to indicate to the ultimate purchaser in the U.S. the English name of the country of origin of the article. Failure to mark an article in accordance with the requirements of 19 U.S.C. 1304 shall result in the levy of a duty of ten percent *ad valorem*. Part 134, Customs Regulations (19 CFR Part 134), implements the country of origin marking requirements and exceptions of 19 U.S.C. 1304.

T.D. 95–25

T.D. 95–25, published in the Federal Register on April 6, 1995 (60 FR 17607), discussed the proper country of origin marking for imported goods produced in the West Bank and Gaza Strip. Prior to the issuance of the T.D., Customs had taken the position that, in order for the country of origin marking of a good which was produced in the West Bank or Gaza Strip to be considered acceptable, the word ''Israel'' must appear in the marking designation. However, by letter dated October 24, 1994, the Department of State advised the Department of the Treasury that, in view of certain developments, principally the Israeli-PLO Declaration of Principles on Interim Self-Government Arrangements (signed on September 13, 1993), the primary purpose of 19 U.S.C. 1304 would be best served if goods produced in the West Bank and Gaza Strip were permitted to be marked ''West Bank'' or ''Gaza Strip.''

Accordingly, as Customs has previously relied upon advice received from the Department of State in making determinations regarding the ''country of origin'' of a good for marking purposes, Customs notified the public in T.D. 95–25 that, unless excepted from marking, goods produced in the West Bank or Gaza Strip shall be marked as ''West Bank,'' ''Gaza,'' or ''Gaza Strip.'' The T.D. further stated that the country of origin markings of such goods shall not contain the words ''Israel,'' ''Made in Israel,'' ''Occupied Territories-Israel,'' or words of similar meaning.

Clarification

Subsequent to the issuance of T.D. 95–25, the Israeli-Palestinian Interim Agreement was signed, granting additional powers and responsibilities to the Palestinian Authority. In addition, an amendment to the United States-Israel Free Trade Area Implementation Act of 1985 (19 U.S.C. 2112 note), enacted on October 3, 1996, authorized the President to proclaim duty-free treatment to products of the West Bank and Gaza Strip. Such duty-free treatment was implemented by Presidential Proclamation 6955 dated November 13, 1996, effective for products of the West Bank and Gaza Strip entered or withdrawn from warehouse for consumption on or after November 21, 1996.

By letter dated January 13, 1997, the Department of State advised the Department of the Treasury that the Palestinian Authority has asked that the U.S. accept the country of origin marking ''West Bank/Gaza'' so as to reaffirm the territorial unity of the two areas. The Department of State further advised that it considers the West Bank and Gaza Strip to be one area for political, economic, legal and other purposes. Accordingly, the Department of State requested that Customs accept the country of origin markings ''West

Bank/Gaza'' and ''West Bank and Gaza'' for products from those areas, and that Customs continue to accept the markings ''West Bank,'' ''Gaza'' and ''Gaza Strip.''

Pursuant to the request of the Department of State, this document notifies the public that acceptable country of origin markings for goods produced in the territorial areas known as the West Bank or Gaza Strip consist of the following: ''West Bank/Gaza,'' ''West Bank/Gaza Strip,'' ''West Bank and Gaza,'' ''West Bank and Gaza Strip,'' ''West Bank,'' ''Gaza,'' and ''Gaza Strip.'' The position stated in this document is effective for merchandise which is entered or withdrawn from warehouse for consumption on or after the date of publication in the Federal Register.

Dated: March 7, 1997.

Stuart P. Seidel,

Assistant Commissioner, Office of Regulations and Rulings.

[FR Doc. 97–6434 Filed 3–13–97; 8:45 am]

BILLING CODE 4820–02–P

[T.D. 97–13]

Revocation of Customs Broker License

AGENCY: U.S. Customs Service, Department of the Treasury.

ACTION: Broker License Revocation.

SUMMARY: Notice is hereby given that pursuant to Section 641, Tariff Act of 1930, as amended, (19 U.S.C. 1641), and Parts 111.51 and 111.74 of the Customs Regulations, as amended (19 CFR 111.51 and 111.74), canceled the following Customs broker license without prejudice.

Port	Individual	License No.
Chicago	William J. Naumes	2835
New York	SAF Customs Brokers, Inc.	10774
Houston	Saratoga Forwarding Co., Inc.	7589
Philadelphia	Dorf International, Inc.	668

Philip Metzger,

Director, Trade Compliance.

[FR Doc. 97–6431 Filed 3–13–97; 8:45 am]

BILLING CODE 4820–02–P

Customs Service

[T.D. 97–15]

Revocation of Customs Broker License

AGENCY: U.S. Customs Service, Department of the Treasury.

ACTION: Broker license revocation.

SUMMARY: Notice is hereby given that on October 28, 1996, the Commissioner of Customs, pursuant to Section 641, Tariff Act of 1930, as amended, (19 U.S.C. 1641), and Parts 111.51 and 111.74 of the Customs Regulations, as amended (19 CFR 111.51 and 111.74), canceled the following Customs broker license with prejudice.

Port	Individual	License No.
Los Angeles	Abraham Shiepe.	7114

Philip Metzger,

Director, Trade Compliance.

[FR Doc. 97–6433 Filed 3–13–97; 8:45 am]

BILLING CODE 4820–02–P

Customs Service

[T.D. 97–14]

Revocation of Customs Broker License

AGENCY: U.S. Customs Service, Department of the Treasury.

ACTION: Broker license revocation.

SUMMARY: Notice is hereby given pursuant to Section 641, Tariff Act of 1930, as amended, (19 U.S.C. 1641), and Parts 111.51 and 111.74 of the Customs Regulations, as amended (19 CFR 111.51 and 111.74), canceling the following Customs broker licenses with prejudice.

Port	Individual	License No.
Houston	Misoon Wada ...	7846
Houston	Amex Trans-World, Inc..	10890

Philip Metzger,

Director, Trade Compliance.

[FR Doc. 97–6432 Filed 3–13–97; 8:45 am]

BILLING CODE 4820–02–P

Corrections

Federal Register
Vol. 62, No. 50
Friday, March 14, 1997

This section of the FEDERAL REGISTER contains editorial corrections of previously published Presidential, Rule, Proposed Rule, and Notice documents. These corrections are prepared by the Office of the Federal Register. Agency prepared corrections are issued as signed documents and appear in the appropriate document categories elsewhere in the issue.

FEDERAL ELECTION COMMISSION

[Notice 1997-1]

Filing Dates for the Texas Special Elections

Correction

In notice document 97–4598 appearing on page 8449 in the issue of Tuesday, February 25, 1997, make the following correction:

On page 8449, in the first column, above the FR Doc. line, the signature was omitted and should read as set forth below:

John Warren McGarry,
Chairman, Federal Election Commission.

BILLING CODE 1505-01-D

NATIONAL SCIENCE FOUNDATION

Special Emphasis Panel in Chemical and Transport Systems (#1190); Notice of Meetings

Correction

In notice document 97–3649 beginning on page 6812 in the issue of Thursday, February 13, 1997, the heading should read as forth above.

BILLING CODE 1505-01-D

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34-38299; File No. SR-Amex-97-01-]

Self-Regulatory Organizations; Notice of Filing of, and Order Granting Accelerated Approval to, Proposed Rule Change by the American Stock Exchange, Inc. Relating to a Pilot Program for Execution of Specialists’ Liquidating Transactions

Correction

In noitce document 97–4527 beginning on page 8464 in the issue of Tuesday, February 25, 1997, make the following correction:

On page 8465, in the first column, in the 20th and 21st lines, ‘‘[insert date 21 days from date of publication]’’ should read ‘‘March 18, 1997’’.

BILLING CODE 1505-01-D

Friday
March 14, 1997

Part II

Department of Energy

Federal Energy Regulatory Commission

18 CFR Parts 35 and 37

Open Access Non-Discriminatory Transmission Services Provided by Public Utilities; Wholesale Competition Promotion; Stranded Costs Recovery by Public and Transmitting Utilities; Final Rule

Open Access Same-Time Information System and Standards of Conduct; Final Rule

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket Nos. RM95–8–001 and RM94–7–002; Order No. 888–A]

Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities

Issued March 4, 1997.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule; order on rehearing.

SUMMARY: The Federal Energy Regulatory Commission (Commission) reaffirms its basic determinations in Order No. 888 and clarifies certain terms. Order No. 888 requires all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to have on file open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory service. Order No. 888 also permits public utilities and transmitting utilities to seek recovery of legitimate, prudent and verifiable stranded costs associated with providing open access and Federal Power Act section 211 transmission services. The Commission's goal is to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the Nation's electricity consumers.

EFFECTIVE DATE: This rule is effective on May 13, 1997.

FOR FURTHER INFORMATION CONTACT:

David D. Withnell (Legal Information—Docket No. RM95–8–001), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, (202) 208–2063

Deborah B. Leahy (Legal Information—Docket No. RM94–7–002), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, (202) 208–2039

Dan T. Hedberg (Technical Information—Docket No. RM95–8–001), Office of Electric Power Regulation, Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, (202) 208–0243

Joseph M. Power (Technical Information—Docket No. RM94–7–002), Office of Electric Power Regulation, Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, (202) 208–1242

SUPPLEMENTARY INFORMATION: In addition to publishing the full text of this document in the Federal Register, the Commission also provides all interested persons an opportunity to inspect or copy the contents of this document during normal business hours in the Public Reference Room at 888 First Street, N.E., Washington, D.C. 20426.

The Commission Issuance Posting System (CIPS), an electronic bulletin board service, provides access to the texts of formal documents issued by the Commission. CIPS is available at no charge to the user and may be accessed using a personal computer with a modem by dialing 202–208–1397 if dialing locally or 1–800–856–3920 if dialing long distance. To access CIPS, set your communications software to 19200, 14400, 12000, 9600, 7200, 4800, 2400, or 1200 bps, full duplex, no parity, 8 data bits and 1 stop bit. The full text of this order will be available on CIPS in ASCII and WordPerfect 5.1 format. CIPS user assistance is available at 202–208–2474.

CIPS is also available through the Fed World system. Telnet software is required. To access CIPS via the Internet, point your browser to the URL address: http://www.fedworld.gov and select the ''Go to the FedWorld Telnet Site'' button. When your Telnet software connects you, log onto the FedWorld system, scroll down and select FedWorld by typing: 1 and at the command line then typing: /go FERC. FedWorld may also be accessed by Telnet at the address fedworld.gov.

Finally, the complete text on diskette in Wordperfect format may be purchased from the Commission's copy contractor, La Dorn Systems Corporation. La Dorn Systems Corporation is also located in the Public Reference Room at 888 First Street, N.E., Washington, D.C. 20426.

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I. Introduction and Summary

On April 24, 1996, the Commission issued Final Rules (Order Nos. 888 and 889) intended to remedy undue discrimination in the provision of interstate transmission services by public utilities and to address the stranded costs that may result from the transition to more competitive electricity markets.[1]

> At the heart of these rules is a requirement that prohibits owners and operators of monopoly transmission facilities from denying transmission access, or offering only inferior access, to other power suppliers in order to favor the monopolists' own generation and increase monopoly profits—at the expense of the nation's electricity consumers and the economy as a whole.

The electric utility industry today is not the industry of ten years ago, or even five years ago. While historically it was assumed that local utilities would be the only ones to generate and transmit power for their customers, today there is a broad array of potential competitors to supply power and widespread transmission facilities that can carry power vast distances. But competitors cannot reach customers if they cannot have fair access to the transmission wires necessary to reach those customers. It is against this industry backdrop that the Commission in Order No. 888 exercised its public interest responsibilities pursuant to sections 205 and 206 of the Federal Power Act (FPA), to reexamine undue discrimination in interstate transmission services and the effect of that discrimination on the electricity customers whom we are bound to protect under the FPA.

We here reaffirm the legal and policy bases on which Order No. 888 is grounded. Utility practices that were acceptable in past years, if permitted to continue, will smother the fledgling competition in electricity markets and undermine the national policies reflected in the Energy Policy Act of 1992 to encourage the development of competitive markets. We firmly believe that our authorities under the FPA not only permit us to adapt to changing economic realities in the electric industry, but also require us to do so, as necessary to eliminate undue discrimination and protect electricity customers. The record supports our conclusion that, absent open access, undue discrimination will continue to be a fact of life in today's and tomorrow's electric power markets. As recent events clearly demonstrate, unbundled electric transmission service will be the centerpiece of a freely traded commodity market in electricity in which wholesale customers can shop for competitively-priced power.

[1] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 FR 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036, *clarified*, 76 FERC ¶ 61,009 and 76 FERC ¶ 61,347 (1996). Order No. 889 is an accompanying rule and specific rehearing arguments on that rule will be addressed separately.

The only way to effectuate competitive markets and remedy discrimination is through readily available, non-discriminatory transmission access. The Commission estimates the potential quantitative benefits from such access will be approximately $3.8 to $5.4 billion per year in cost savings, in addition to the non-quantifiable benefits that include better use of existing assets and institutions, new market mechanisms, technical innovation, and less rate distortion.

Order No. 888 has two central components. The first requires all public utilities that own, operate or control interstate transmission facilities to offer network and point-to-point transmission services (and ancillary services) to all eligible buyers and sellers in wholesale bulk power markets, and to take transmission service for their own uses under the same rates, terms and conditions offered to others. In other words, it requires non-discriminatory (comparable) treatment for all eligible users of the monopolists' transmission facilities. The non-discriminatory services required by Order No. 888, known as open access services, are reflected in a pro forma open access tariff contained in the Rule. The Rule also requires functional separation of the utilities' transmission and power marketing functions (also referred to as functional unbundling) and the adoption of an electric transmission system information network.

The second central component of Order No. 888 was to address whether and how utilities will be able to recover costs that could become stranded when wholesale customers use the open access tariffs, or FPA section 211 tariffs,[2] to leave their utilities' power supply systems and shop for power elsewhere. Because of competitive changes occurring at the retail level, as numerous states have begun retail transmission access programs, Order No. 888 also clarifies whether and when the Commission may address stranded costs caused by retail wheeling and the extent of the Commission's jurisdiction over unbundled retail transmission. The Commission further addresses the circumstances under which utilities and their wholesale customers may seek to modify contracts made under the old regulatory regime, taking into account the goals of reasonably accelerating customers' ability to benefit from competitively priced power and at the same time ensuring the financial stability of electric utilities during the transition to competition.

137 entities filed requests for rehearing and/or clarification of Order No. 888. While these parties raise a variety of arguments—including legal, policy, and technical arguments—the majority (including a majority of public utilities) agree that we need to harness the benefits that competitive electricity markets can bring to the nation. The disagreements primarily focus on the mechanics of how we should do this, who should pay the costs of the transition to competition, and how long the transition should take.

First, parties disagree on what is necessary to remedy undue discrimination and to develop truly competitive wholesale markets. Many focus specifically on the tariff terms and conditions of good transmission access and seek changes in the Order No. 888 pro forma tariff. In response to these types of rehearing arguments, the Commission has fine-tuned or changed some of the pro forma tariff terms and conditions to better ensure that they do not permit discrimination and that they result in well-functioning markets. Other petitioners focus on additional structural changes which they believe are necessary, such as mandatory corporate restructuring (divestiture of generation assets) or mandatory creation of independent transmission system operators (ISOs). With regard to restructuring, the Commission continues to believe that functional unbundling of the utility's business, not corporate divestiture or mandatory ISOs, is sufficient to remedy undue discrimination at this time.

The most contentious arguments raised on rehearing involve how we deal with the transition costs associated with moving to competition. Some utilities have invested millions of dollars in facilities and purchased power contracts based on an explicit or implicit obligation to serve customers and the expectation that those customers would remain on their systems for the foreseeable future. These utilities face so-called ''stranded costs'' which, if not recovered from the customers that caused the costs to be incurred, could be shifted to other customers.

There are two basic categories of rehearing arguments regarding stranded cost recovery. Most utilities want a guarantee from this Commission that they will recover all stranded costs, whether caused by losing retail customers or wholesale customers. Many customers, on the other hand, want to be able to abrogate existing power supply contracts so that they can immediately leave their current suppliers' systems and shop for cheaper power elsewhere, without paying the sunk costs that their suppliers incurred on their behalf.

In response to these diverse arguments, the Commission has struck a reasonable balance that, for certain defined circumstances, permits utilities the *opportunity* to seek extra-contractual recovery of stranded costs from their departing customers and permits customers the *opportunity* to make a showing that their contracts should be shortened or terminated. Based on our experience in the natural gas area, we have learned that it is critical to address these issues early, but we also have chosen an approach different from that taken in the gas area because of the different circumstances facing the electric industry.

In balancing the wide array of interests reflected in the rehearing petitions, we have made a number of clarifications and granted rehearing on some issues, but we reaffirm the core elements and framework of Order No. 888. Since the time the final rules issued, as discussed in Section III, the pace of competitive change has continued to escalate in the industry at both the wholesale and retail levels as competitors, customers and state regulatory authorities aggressively seek ways to lower the price of electricity. We therefore believe it is all the more critical that we remedy undue discrimination in interstate transmission services now, and that we do so generically, if we are to fulfill our responsibilities under the FPA to protect consumers and provide a fair and orderly transition to new competitive markets.

Finally, with respect to environmental issues associated with this rulemaking, certain parties on rehearing continue to challenge the adequacy of our Final Environmental Impact Statement (FEIS). The central issues are whether the Final Rule will increase emissions of nitrogen oxides (NOx) from certain fossil-fuel fired generators, which could affect air quality in downwind areas to which these emissions may be carried, and the Commission's authority to mitigate environmental consequences.

We deny rehearing on the environmental issues raised and affirm our conclusion that we have satisfied our obligations under NEPA. As discussed in detail in the Final Rule, this rulemaking is expected to slightly increase or slightly decrease total future

[2] Under section 211 of the FPA, the Commission, on a case-by-case basis upon application by an eligible customer, may order both public utilities and non-public utilities that own or operate transmission facilities used for the sale of electric energy at wholesale to provide transmission services to the applicant if it finds it is in the public interest to issue such order.

NOx emissions, depending on whether competitive conditions in the electric industry favor the utilization of natural gas or coal as a fuel for the generation of electricity. We also examined mitigation options over the longer term, and found that the preferred approach for mitigating any adverse environmental consequences would be for the Environmental Protection Agency (EPA) and the states to address the problem through regulatory authorities available under the Clean Air Act. The petitions for rehearing have not persuaded us to change this approach. Indeed, we note that since the issuance of Order No. 888, the EPA has concluded that the Rule is unlikely to have any immediate significant adverse environmental impact and thus concurred that the Commission's analysis is adequate under NEPA. We further note that EPA has recently taken steps under the Clean Air Act to address NOx emissions as part of a comprehensive emissions control program, along the lines endorsed by the Commission in the EIS.

In summary, the Commission believes that our authorities under the FPA not only permit us to adapt to changing economic realities in the electric industry, but also require us to do so to eliminate undue discrimination and protect electricity customers. The measures required in Order No. 888 are necessary to remedy undue discrimination in interstate transmission services and provide an orderly and fair transition to competitive bulk power markets.

To assist the reader, we provide below a section-by-section summary of key elements of this Order on Rehearing.

Scope of the Rule

In this section we discuss petitions to rehear our requirement that transmission and power sales services be contracted for separately (unbundled). We reaffirm that this requirement is a reasonable and workable means of assuring non-discriminatory open access transmission. In doing so we refuse invitations to require that utilities under our jurisdiction divest themselves of generation or transmission assets. We do, however, make an important clarification involving how we will deal with existing contracts that contain so-called *Mobile-Sierra* clauses (clauses under which one or both parties agreed not to seek modification of contract terms unless they could show that it is contrary to the public interest not to permit the modification).

In Order No. 888 we concluded that contracts would not be abrogated by operation of the Rule. Instead, preexisting contracts would continue to be honored until such time as they were revised or terminated. We also found that those who were operating under pre-existing requirements contracts containing *Mobile-Sierra* clauses would nonetheless be allowed to seek reform of the contracts on a case-by-case basis. On rehearing we affirm that public utilities will be allowed to file to amend their *Mobile-Sierra* contracts for the limited purpose of providing an opportunity to seek recovery of stranded costs, without having to make a public interest showing that such cost recovery should be permitted. However, these utilities will have the burden, on a case-by-case basis, of showing that they had a reasonable expectation of continuing to serve the departing customer after the contract term. We clarify that if the utilities under such contracts seek to modify provisions that do *not* relate to stranded costs, they will have the burden of showing that the provisions are contrary to the public interest.

We here make clear that, in turn, customers will be allowed to file to amend their *Mobile-Sierra* contracts to modify any contract term or to terminate the contract, without having to make a showing that the contract terms are contrary to the public interest. Instead, customers seeking modifications must demonstrate that the provisions they wish modified are no longer ''just and reasonable.'' We reaffirm our conclusion in the Final Rule that if a customer seeks to shorten or eliminate the term of its contract, however, any contract modification approved by the Commission will provide for appropriate stranded cost recovery by the customer's supplying utility.

These various provisions meet the two-fold need to deal with stranded costs and the contracts under which those costs were incurred. However, as described in Order No. 888, the opportunity to reform *Mobile-Sierra* contracts extends only to a limited set of contracts—those entered into on or before July 11, 1994, for requirements power.

Comparability

In this section we deal with those requesting rehearing of our conclusions regarding what ''comparable'' service is, who is eligible for that service, and how it is to be implemented. We reaffirm our finding that, as a matter of law, we have jurisdiction over the rates, terms and conditions of unbundled transmission service provided to retail customers. We also clarify that we have authority to order ''indirect'' unbundled retail transmission services and that if such transmission is ordered by us in the future, or if it is provided voluntarily, otherwise eligible customers may obtain such service under the open access tariff. We expect public utilities to provide such service in the future and, if they do not, we will not hesitate to order it.

We modify in two respects the definition of who is eligible for open access transmission service. First, we clarify that, with respect to service that this Commission is prohibited from ordering by section 212(h) of the Federal Power Act (retail wheeling directly to an ultimate consumer and ''sham'' wholesale wheeling), entities are eligible for such service under the tariff only if it is provided pursuant to a state requirement or is provided voluntarily. Second, we clarify that retail customers taking unbundled service pursuant to a state requirement (*i.e.*, direct retail service) are eligible for such service only from those transmission providers that the state orders to provide service. These changes are made to make clear that our rules cannot be used to circumvent the proscriptions placed on the Commission against ordering direct retail wheeling.

Ancillary Services

In this section we deal with petitions to rehear our definitions of ancillary services—those services such as scheduling, voltage control, and supplemental reserve service that must or can attend the providing of transmission service—as well as the provisions involving these services. We reaffirm that tariffs must separately state the charges for these services. We do modify some of the definitions of these services to conform to industry needs and practices. Most importantly, we make clear that the transmission provider's sale of ancillary services associated with providing basic transmission service is not a wholesale merchant function and thus does not violate the standards of conduct imposed with Order No. 889.

Coordination Arrangements

The requirement to provide non-discriminatory open access transmission applies to any agreement between utilities that contains transmission rates, terms or conditions. This includes pooling arrangements and agreements between companies contracting to provide each other mutually beneficial transmission services. In Order No. 888 we laid out rules under which the open access comparability requirements would apply to tight and loose power pools, public utility holding companies and bilateral coordination agreements.

We also set out principles that would govern our approval of independent system operator (ISO) agreements.

In this section we affirm the rules governing coordination agreements. In doing so we clarify the definition of ''loose pool.'' We also make clear that, unlike in other situations where we require utilities to provide not only the services they provide themselves but those they could provide themselves, we will require members of loose pools to offer to third parties only those transmission services that they provide themselves under their pool-wide agreements.

We also reaffirm our strong commitment to the concept of ISOs and the ISO principles described in Order No. 888. In doing so we reject arguments that we should require that ISOs be formed. At the same time, we emphasize that while there is no ''cookie-cutter'' approach to forming an acceptable ISO, the requirement of fair and non-discriminatory rules of governance (Principle One) and the requirement that ISO employees have no financial interest in the economic interests of power marketers—backed by strict conflict of interest provisions—(Principle Two) are fundamental to our approving any ISO.

Pro Forma Tariff Provisions

The pro forma tariff is the basic mechanism implementing the requirements of comparable open access transmission. It provides the details of the transmission service obligations imposed on jurisdictional utilities by the Rule. On rehearing we affirm most of the provisions set out in Order No. 888 for the pro forma tariff. We do make changes to conform the pro forma tariff to changes adopted under other sections (for example, the definition of ''eligible customer'').

The rehearing petitions raised many questions about how particular aspects of the tariff will work. For the most part, these questions cannot be answered generically, but must be resolved on a case-by-case basis in the context of specific fact situations. However, the petitions brought to light issues that require clarifications and in some cases revisions to the tariff. The most significant of these involve discounting practices, provisions governing priority of service and curtailment, and the reciprocity provision.

Discounting practices. Originally, we provided different rules depending upon whether the transmission provider was offering a discount to itself or an affiliate or offering a discount to a non-affiliate. In response to the rehearing petitions, we are making three significant changes to the discounting requirements to better permit the ready identification of discriminatory discounting practices while also providing greater discount flexibility.

First, any discount offered on transmission services (including supporting ancillary services) by a transmission provider or requested by any customer must now be made only over the OASIS. With this change, all will have the same, timely access to discounted services. In making this change, we clarify that a transmission provider may limit its discounted service to particular time periods.

Second, once the provider and customer agree on a discount, the details of the discounted service—the price, points of receipt and delivery, and length of service—must be immediately posted on the OASIS.

Third, we revise our Rule respecting what other transmission paths must be offered at a discount. Originally, in Order No. 888, we required that when a discount was offered over one path, the transmission provider would have to provide that discount over all other unconstrained paths on its system. We will no longer require this. Instead, the discount will be limited to those unconstrained paths that go to the same point(s) of delivery as the discounted service being provided on the transmission provider's system. The discount will extend for the same time period and must be offered to all transmission service customers.

Priority and Curtailment. We affirm the right of first refusal policy that reservation priority continues for firm service customers served under a contract of one year or more. We also affirm that curtailment must be made on a pro-rata basis and clarify that non-firm point-to-point service is subordinate to firm service. However, we clarify that the pro-rata curtailment requirement extends to only those transactions that alleviate the constraint.

Reciprocity. In Order No. 888 we conditioned the use of a public utility's open access service on the agreement that, in return, it is offered reciprocal service by non-public utilities that own or control transmission facilities. Such reciprocal service does not have to be through an open access tariff, i.e., a tariff available to all eligible customers, but may be limited to those public utilities from whom the non-public utility obtains open access service. We affirm the reciprocity condition. In doing so, however, we make several clarifications.

First, a public utility is free to offer transmission service to a non-public utility without requiring reciprocal service in return. In other words, it may voluntarily waive the reciprocity condition. However, if it chooses to do so, transmission service must be provided through the pro forma tariff. Alternatively, bilateral agreements for transmission service provided by the public utility will not be permitted.

Second, we clarify that under the reciprocity condition a non-public utility must agree to offer the Transmission Provider any transmission service the non-public utility provides or is capable of providing on its system. This means that the non-public utility undertaking reciprocity must have an OASIS and must operate under the standards of conduct imposed under Order No. 889 unless it is granted a waiver by the Commission or, where appropriate, by a regional transmission group (RTG) of which it is a member. We also clarify that a non-public utility cannot avoid its responsibilities by obtaining transmission service through other transmission customers. Further, the seller as well as the buyer in the chain of a transaction involving a non-public utility will have to comply with the reciprocity condition.

Third, we adhere to our decision not to treat generation and transmission (G&T) cooperatives and their member distribution cooperatives as a single unit. Thus, the reciprocity provision extends to the G&T Cooperative and not to its member distribution cooperatives.

Fourth, we clarify the ''safe harbor'' provision under which a non-public utility may get a Commission decision that its transmission tariff suffices to meet reciprocity. A non-public utility may limit the use of any reciprocity tariff that it voluntarily files at the Commission to those transmission providers from whom the non-public utility obtains open access service. A non-public utility also may satisfy reciprocity through bilateral agreements with a public utility. As a related matter, if a public utility believes a non-public utility is violating the reciprocity condition, it may file with the Commission a petition to terminate its service to the non-public utility.

Fifth, we clarify that non-public utilities may include stranded cost provisions in their reciprocity tariffs.

Sixth, the order on rehearing removes the term ''interstate'' from the reciprocity provisions. This is to make clear that reciprocity applies even to those who do not own or control interstate transmission facilities; *i.e.*, foreign utilities and those located in the ERCOT region of Texas.

As to local furnishing bonds held by some public utilities, we clarify that all costs associated with the loss of tax-exempt status of those bonds caused by providing open access transmission service are properly considered costs of providing that service. This includes costs of defeasing, redeeming, and refinancing those bonds.

Other Clarifications. In this order on rehearing we take the opportunity to clarify various other tariff provisions. Among these: Transmission providers do not have to take service under the open access tariff for transmitting power purchased on behalf of their bundled retail customers. Also, the ability to reserve capacity to meet the reliability needs of a transmission provider's native load applies equally to present transmission and transmission that is built in the future.

Implementation

On rehearing, we make no substantive changes to the implementation provisions originally required under Order No. 888. For the most part, the implementation process has been completed. Utilities have made the requisite tariff and compliance filings and public and non-public utilities have, through other orders, been provided guidance as to obtaining waivers of Order No. 888 and Order No. 889 requirements.

We emphasize that we do not require the abrogation of existing contracts. Rather, the Rule requires only that transmission providers offer transmission under the open access tariff in addition to existing service obligations. Commitments made under existing contracts will continue. Of course, both transmission providers and their customers may seek to revise the terms and conditions of existing contracts by making the necessary filings, as appropriate, under Sections 205 or 206 of the Federal Power Act.

State and Federal Jurisdiction

On rehearing we reaffirm our decision that when transmission service is provided to serve retail customers apart from any contract for the retail sale of power, i.e., when it is provided on an unbundled basis, that transmission service is under our jurisdiction. In today's market, and increasingly in the future as more states adopt retail wheeling programs, retail transactions are, and will be, broken down into products that are sold separately— transmission and generation—and sold by different entities. The exercise of our jurisdiction over the rates, terms and conditions of unbundled retail transmission will, therefore, become more important. We also recognize that states have jurisdiction over facilities used for local distribution.

On rehearing we also reaffirm the seven-factor test of Order No. 888 to distinguish transmission under our jurisdiction from state-jurisdictional local distribution. In doing so, we recognize that our test does not resolve all possible issues. There may be other factors that should be taken into account. The test, therefore, is designed for flexibility to include unique local characteristics and usages. To that end, we will continue to defer to state findings on these matters.

In addition, we clarify that states have the authority to determine the retail marketing areas of the electric utilities within their respective jurisdictions. We also recognize that states have the concomitant authority to determine the end user services these utilities provide.

Stranded Costs

On rehearing, we reaffirm our basic decisions surrounding the recovery of stranded costs. Utilities will be allowed the opportunity to seek to recover legitimate, prudent, and verifiable wholesale stranded costs. This opportunity is limited to costs associated with serving customers under wholesale requirements contracts executed on or before July 11, 1994 that do not contain explicit stranded cost provisions; and costs associated with serving retail-turned-wholesale customers.

We clarify that we will consider on a case-by-case basis whether to treat a contract extended or renegotiated without a stranded cost provision as an existing contract for stranded cost purposes.

In each case, the opportunity to seek stranded costs is limited to situations in which there is a direct nexus between the availability and use of a Commission-required transmission tariff and the stranding of the costs. The Rule does not allow the recovery of costs that do not arise from the new, accelerated availability of non-discriminatory transmission access.

The Commission also reaffirms its decision that stranded costs should be recovered from the customer that caused the costs to be incurred. The Commission is not requiring other remaining customers, or the utility, to shoulder a portion of its stranded costs that meet the requirements for recovery.

The Commission, as described in Order No. 888, will be the primary forum for addressing the recovery of stranded costs caused by retail-turned-wholesale customers. With respect to such cases, we have made several changes.

First, the Commission has reconsidered its decision respecting cases involving existing municipal utilities that annex retail customer service territories. Under Order No. 888, we found that in such cases the Commission should not be the primary forum for determining stranded cost recovery. On rehearing we now find that such cases should fall within our province.

Second, we clarify that the opportunity for recovery of stranded costs associated with retail-turned-wholesale customers applies regardless of whether the customer or its new supplier is the one requesting and contracting for the transmission service. To this end, we have revised the definition of ''wholesale stranded cost.''

With respect to the recovery of stranded costs caused by unbundled retail wheeling, we affirm that the only circumstance in which we will entertain requests for these types of costs is when the state regulatory authority does not have authority under state law to address stranded costs when the retail wheeling is required. We clarify that if a state regulatory authority has in fact addressed such costs, regardless of whether it has allowed full recovery, partial recovery or no recovery, utilities may not apply to the Commission to recover stranded costs caused by the retail wheeling.

Other

In this section we resolve questions concerning our information reporting requirements, regional transmission groups, and the special situations posed by utilities in the Pacific Northwest and by federal power marketing and similar agencies. Here we make some minor clarifications but make no significant changes to Order No. 888.

We are not persuaded that the information reporting requirements need to be changed at this time. Finally, we reject arguments that would have us fix generically any particular rate methodology for providing open access transmission service under the pro forma tariff.

II. Public Reporting Burden

This order on rehearing issues a number of minor revisions to the Final Rule. We find, after reviewing these revisions, that they do not, on balance, increase the public reporting burden.

The Final Rule contained an estimated annual public reporting burden based on the requirements of the Open Access Final Rule and the Stranded Cost Final Rule.[3] Using the

[3] 61 FR 21540 at 21543; FERC Stats. & Regs. ¶ 31,036 at 31,638 (1996). No comments were filed

Continued

burden estimate contained in the Final Rule as a starting point, we evaluated the public burden estimate contained in the Final Rule in light of the revisions contained in this order and assessed whether this estimate needed revision. We have concluded, given the minor nature of the revisions, and their offsetting nature, that our estimate of the public reporting burden of this order on rehearing remains unchanged from our estimate of the public reporting burden contained in the Final Rule. The Commission has conducted an internal review of this conclusion and has assured itself that there is specific, objective support for this information burden estimate. Moreover, the Commission has reviewed the collection of information required by the Final Rule, as revised by this order on rehearing, and has determined that the collection of information is necessary and conforms to the Commission's plan, as described in the Final Rule, for the collection, efficient management, and use of the required information.

Persons wishing to comment on the collections of information required by the Final Rule, as modified by this order on rehearing, should direct their comments to the Desk Officer for FERC, Office of Management and Budget, Room 3019 NEOB, Washington, D.C. 20503, phone 202–395–3087, facsimile: 202–395–7285 or via the Internet at hillier__t@a1.eop.gov. Comments must be filed with the Office of Management and Budget within 30 days of publication of this document in the Federal Register. Three copies of any comments filed with the Office of Management and Budget also should be sent to the following address: Ms. Lois Cashell, Secretary, Federal Energy Regulatory Commission, Room 1A, 888 First Street, N.E., Washington, D.C. 20426. For further information, contact Michael Miller, 202–208–1415.

III. Background

In the Final Rule, we detailed the events that led up to this rulemaking, including the significant technical, statutory and regulatory changes that have occurred in the electric industry since the FPA was enacted in 1935.[4] In particular, we focused on the competitive influences of the Public Utility Regulatory Policies Act of 1978, the Congressional mandate in the Energy Policy Act of 1992 to encourage competition in electricity markets, and the need for reform in the industry if consumers are to achieve the benefits that greater competition can bring.

In the ten months since the Final Rule issued, competitive changes have escalated at an even faster pace in virtually all areas of the electric industry. These changes are driven not only by the Commission's Final Rule, but also by state restructuring initiatives and by continuing pressures from customers to take advantage of emerging competitive markets and the lower electricity rates they can bring.

All of the existing 166 public utilities that own, control or operate interstate transmission facilities (listed as Group 1 and Group 2 utilities in the Final Rule) have filed the Order No. 888 pro forma open access tariff or requested a waiver of the requirement. Similarly, they either have adopted an electronic information network or requested a waiver of the requirement. Five non-public utilities have submitted reciprocal transmission tariffs and more than 20 have requested a waiver of the reciprocity condition in the pro forma tariff.[5]

Significant competitive changes also have accelerated with respect to power pooling, state restructuring initiatives, and Independent System Operators (ISOs). Under Order No. 888 and subsequent implementation orders, the Commission required the filing of revised pooling agreements and joint pool-wide transmission tariffs by December 31, 1996, in order to remedy undue discrimination in transmission services provided through interstate power pooling arrangements. Among the power pool filings were a New England (NEPOOL) comprehensive restructuring proposal, a New York proposal, a Pennsylvania-New Jersey-Maryland (PJM) compliance filing and a Western Systems Power Pool filing.

In response to the Commission's encouragement in Order No. 888 of ISOs as a possible means for accomplishing comparable access, a number of utilities and states are well underway in developing this new institution. The fundamental purpose of an ISO is to operate the transmission systems of public utilities in a manner that is independent of any business interest in sales or purchases of electric power by those utilities. The Commission has received several proposals for forming ISOs, one as part of the multi-docketed filing engendered by California's restructuring plan, and others relating to power pool filings. A number of regions are also developing ISO proposals. Some regions previously considering regional transmission groups (RTGs), whose primary purpose is regional planning of transmission facility construction and upgrades, have now broadened their discussions to include an ISO.

Investor-owned utilities in California, at the order of both the state commission and the legislature, have filed proposals with the Commission that would transfer control of transmission facilities to an ISO in conjunction with the formation of a state-wide power exchange to facilitate both wholesale and retail access. While the case presents many complex issues for the Commission to resolve, the California proposal is fundamentally compatible with the pro-competitive open-access requirements of Order Nos. 888 and 889. The Commission's open-access policies therefore have provided a framework for California, and other states, to explore customer choice initiatives.

Other major regions of the country also are instituting ISOs. Member utilities of the PJM Power Pool filed competing ISO proposals with the Commission and are currently working to reconcile the differences between their proposals. The New York Power Pool recently filed a proposal to create an ISO and a power exchange for New York. The New England Power Pool is exploring a new industry structure for its region that centers on the creation of an ISO. Utilities and other market participants in the Electric Reliability Council of Texas have also formed an ISO. Discussions are underway among utilities from Virginia to Wisconsin in an attempt to create a Midwestern ISO. Members of the Mid-America Power Pool are discussing an ISO proposal. In the Pacific Northwest, utilities are involved in negotiations intended to lead to the formation of an independent grid operator (Indego).

The combined available generation resources of the utilities in these groups is on the order of 428 GW out of a total of approximately 732 GW for total U.S. resources (as of the end of 1996). Thus, assuming these ISO arrangements come to fruition, about three-fifths of the industry may have independent system operators controlling their transmission systems.

Moreover, every state but one has proposed or is considering or developing retail competition programs. For example, New Hampshire, Illinois

in objection to the public burden estimate contained in the Open Access Final Rule and the Stranded Cost Final Rule.

[4] FERC Stats. & Regs. at 31,638–52; *mimeo* at 13–51.

[5] As a condition of using a public utility's open access tariff, any user, including non-public utilities, must offer reciprocal comparable transmission access to the public utility in return. Order No. 888 provides a voluntary mechanism whereby non-public utilities can obtain Commission confirmation that what they are offering meets the tariff reciprocity condition. Non-public utilities also may seek a waiver of the reciprocity condition.

and Massachusetts began pilot programs in the past year, and retail transmission service for these pilot programs currently is being taken pursuant to tariffs approved by both the state commissions and this Commission. The Massachusetts Department of Public Utilities has sent a proposal to the state legislature calling for retail competition to begin in January 1998. The New York Public Service Commission has issued an order proposing that retail competition begin in early 1998. The New Jersey Board of Public Utilities has issued a proposal permitting customer choice beginning in October of 1998. The Vermont Public Service Board has sent a plan to the legislature recommending that full customer choice begin by the end of 1998. The Arizona Corporation Commission has adopted rules to phase in competition over four years, beginning in January 1999. Recently, the Maine Public Utilities Commission issued a final report and recommendation to the legislature for retail competition to begin in January 2000. In addition, Rhode Island and Pennsylvania both have new laws requiring customer choice. These are only a few of the many state initiatives that are under way that will dramatically alter the structure of the electric industry.

Since Order No. 888 was issued, significant efforts also have been made to ensure that reliability of the transmission grid is maintained and that reliability criteria are compatible with competitive markets. The North American Electric Reliability Council (NERC) has continued its efforts to broaden its membership and to fashion reliability requirements to fit a more competitive electric power industry. For example, the NERC Board of Directors voted to require mandatory compliance by all power market participants with its reliability standards. NERC is also establishing new entities called regional security coordinators to oversee the stability of grid operations and to direct the development of an extensive new communications network. Various NERC committees are considering ways to improve the tracking of power transactions, identify the network impacts of transactions, and reflect the actual flow of power over the network when making reservations for transmission service. These efforts are likely to intensify as the industry continues to adapt to competitive changes occurring in the marketplace.

Thus, all segments of the electric industry have taken significant steps in the past year in response to the emerging wholesale competitive markets enabled by Order No. 888 as well as state retail competition initiatives. The competitive framework established by Order No. 888, whose centerpiece is non-discriminatory transmission services and a fair and orderly stranded cost recovery mechanism, is critical to the successful transition to, and full development of, the industry restructuring proposals that are well underway in all major regions of the country.

IV. Discussion

A. Scope of the Rule

1. Introduction

Rehearing Requests

Severability of Rules

Several entities assert that the Commission should find that the requirements of open access transmission and stranded cost recovery are not severable.[6] They argue that if one of these provisions is invalidated by a court or otherwise removed, the orders in their entirety should be withdrawn or stayed pending reconsideration by the Commission, and public utilities should be allowed to withdraw or file amended transmission tariffs.

Commission Conclusion

The Commission will not, at this time, make any determination whether or not the open access transmission, stranded cost recovery and OASIS provisions of Order Nos. 888 and 889 are severable. Accordingly, we make no finding whether, if one of these provisions is invalidated, Order Nos. 888 and 889 should be withdrawn or stayed in their entirety. We believe that our decisions in Order Nos. 888 and 889 will be upheld by the courts. Moreover, it would be premature to consider the appropriateness of a stay or withdrawal at this time. Circumstances at the time of any court order would dictate how we should proceed and we would consider all such circumstances, and the entirety of our policy decisions, before determining how to respond to a court decision.

2. Functional Unbundling

In the Final Rule, the Commission found that functional unbundling of wholesale generation and transmission services is necessary to implement non-discriminatory open access transmission.[7] At the same time, the Commission recognized that additional safeguards were necessary to protect against market power abuses. Thus, the Commission adopted a code of conduct, discussed in detail in the final rule on OASIS, to ensure that the transmission owner's wholesale power marketing personnel and the transmission customer's power marketing personnel have comparable access to information about the transmission system. The Commission also noted that section 206 of the FPA is available if a public utility seeks to circumvent the functional unbundling requirements.

As a further precaution against unduly discriminatory behavior, the Commission stated that it will continue to monitor electricity markets to ensure that functional unbundling adequately protects transmission customers. The Commission also indicated that it would continue to observe both the evolution of competitive power markets and the progress of the industry in adapting structurally to competitive markets. If it subsequently becomes apparent that functional unbundling is inadequate or unworkable in assuring non-discriminatory open access transmission, the Commission indicated that it would reevaluate its position and decide whether other mechanisms, such as ISOs, should be required.

The Commission concluded that functional unbundling, coupled with these safeguards, is a reasonable and workable means of assuring that non-discriminatory open access transmission occurs. In the absence of evidence that functional unbundling will not work, the Commission indicated that it was not prepared to adopt a more intrusive and potentially more costly mechanism—corporate unbundling—at this time.

Rehearing Requests

Several entities disagree with the Commission's decision to require functional unbundling of wholesale generation and transmission as a means of assuring non-discriminatory open access transmission.[8] American Forest & Paper argues that utilities must be required to divest or spin-off their generating assets through operational unbundling or divestiture. It alleges that it was arbitrary and capricious, and not supported by evidence, for the Commission to rely on a monopolist's code of conduct to protect against monopoly abuses. Nucor asserts that a financial conflict of interest remains and that the Commission cannot monitor the exchanges of information between utility generation and transmission employees. It declares that a credible

[6] *E.g.*, Nuclear Energy Institute, Southern, EEI. EEI and Nuclear Energy Institute also argue that Order No. 889 should not be severable.

[7] FERC Stats. & Regs. at 31,654–56; *mimeo* at 57–61.

[8] *E.g.*, American Forest & Paper, Nucor, NY Municipal Utilities.

information disclosure requirement is needed that makes generation cost and production data visible to all participants on a same-time basis. NY Municipal Utilities also believes that the Commission did not go far enough and argues that the Commission should have required operational unbundling, at least for tight power pools.

Commission Conclusion

The Commission reaffirms its finding in the Final Rule that, based on the information available at this time, functional unbundling, along with the flexible safeguards discussed in the Final Rule, is a reasonable and workable means of assuring non-discriminatory open access transmission. We see no need to adopt a more intrusive and potentially more costly approach at this time based on speculative allegations that functional unbundling may not work and that more severe measures may be needed. Indeed, despite a number of opportunities to do so, no entity has submitted any evidence suggesting that this less intrusive approach would not work. We do emphasize, however, that we have not adopted a rigid approach, but have indicated a willingness to monitor the situation and, if events require, reevaluate our decision and decide whether another mechanism may be more appropriate. Until we see evidence that functional unbundling will not work, we will continue to require functional unbundling, with the safeguards enumerated in the Final Rule and in Order No. 889.

3. Market-Based Rates

a. Market-Based Rates for New Generation

In the Final Rule, the Commission codified its determination in *Kansas City Power & Light Company* (*KCP&L*) [9] that the generation dominance standard for market-based sales from new capacity should be dropped.[10] The Commission explained that it had yet to find an instance of generation dominance in long-run bulk power markets and no commenter had presented any evidence to that effect. However, the Commission emphasized that it will not ignore specific evidence presented by an intervenor that a seller requesting market-based rates for sales from new generation nevertheless possesses generation dominance.

The Commission further clarified that dropping the generation dominance standard for new capacity does not affect the demonstration that an applicant must make in order to qualify for market-based rates for sales from its existing generating capacity.

Rehearing Requests

Several entities take issue with the Commission's determination to drop the generation dominance standard for market-based sales from new capacity.[11] American Forest & Paper argues that the Commission should delay its decision until effective competition has been demonstrated to exist in all markets. SC Public Service Authority maintains that the Commission must determine on a case-by-case basis whether public utilities have market power (for both existing and new capacity). It further argues that the Commission must develop an analysis of structural conditions to use in assessing the potential for market power consistent with that used by DOJ and FTC in merger proceedings and that reflects the conditions of the industry. SC Public Service Authority also asserts that the Commission must require as a condition of market rates for sales in the bulk power market, which it defines to be limited to sales to integrated utilities, that the selling utility file rate cases with the Commission and the applicable state commissions to avoid subsidization by captive consumers.

TDU Systems alleges that the long-run bulk power market upon which the *KCP&L* decision was based is overly broad and ignores the distinction between firm power, which ''entities subject to others' market power are most commonly in need of'' and other bulk power services. TDU Systems take issue with the Commission's conclusion in *KCP&L* that large numbers of capacity offers from IPPs and QFs demonstrate that the market abounds with competitors. TDU Systems argues that the Commission's ''assumption that large numbers of offers of *power* equate with large numbers of offers of *firm* power is questionable at best, and very likely incorrect.'' [12] Similarly, LEPA argues that the Commission ignored evidence submitted by LEPA in comments ''that the transmission dominant utility still retained monopoly power over RQ [requirements] markets on which LEPA's members are dependent for their bulk power supply.'' Because the Commission ignored the RQ market and the evidence of concentration in that market, LEPA asserts that the Commission's decision is reversible error. LEPA further argues that the Commission ignored the undisputed testimony of LEPA's witness that reliability requirements constrain the geographic scope of the RQ market severely.

San Francisco argues that the burden to demonstrate affirmatively the absence of capacity constraints as a precondition to receiving authority to charge market-based rates for sales from new capacity should be upon public utility applicants, who possess the information concerning capacity constraints.

Commission Conclusion

We reaffirm our decision to codify the determination in *KCP&L* that the generation dominance standard for market-based sales from new capacity should be dropped. Petitioners have not presented any evidence that demonstrates generation dominance in long-run bulk power markets and, as discussed in Order No. 888, we have found no such evidence of generation dominance in any of the numerous market-based rate cases decided by the Commission since *KCP&L*. In addition, as described in Order No. 888, the Commission will consider evidence of generation dominance, including generation dominance that results from transmission constraints, when such evidence is presented by an intervenor in a market-based rate case in which a utility seeks market-based pricing associated with new capacity.

American Forest & Paper's argument that the Commission should delay codification of *KCP&L* until effective competition has been demonstrated to exist in all markets ignores the fact that we have eliminated the generation dominance standard for market-based rates from new capacity only, and that the generation standard still applies to applications for market-based rates from existing generation. Other entities similarly argue that other markets in which utilities may sell power from new capacity may be highly concentrated with respect to generation, or that these utilities may otherwise be able to exert market power. Specifically, TDU Systems and LEPA express concern that the new policy may result in the exercise of market power over very specific bulk power products.

To allay these concerns, we note that eliminating the generation dominance showing applies only to sales from new capacity. It does not apply to entire classes of service or to specific products. In addition, the policy eliminates the showing only as a matter of routine in each filing. We reemphasize that the Commission will consider specific evidence of generation dominance

[9] 67 FERC ¶ 61,183 at 61,557 (1994).

[10] FERC Stats. & Regs. at 31,656–57; *mimeo* at 63–66.

[11] *E.g.,* American Forest & Paper, SC Public Service Authority, TDU Systems, LEPA, San Francisco.

[12] TDU Systems at 92.

associated with new capacity at the time the seller seeks market-based rates for the new capacity, including whether the addition of the new capacity, when combined with existing capacity, results in generation dominance. This clearly includes situations where existing sources of generation must be combined with new resources to produce a firm power supply. Where entry barriers are a concern, intervenors are free to raise the issue.

SC Public Service Authority also raises a number of concerns relating to the ability of utilities to exercise market power if they are permitted to sell new capacity at market-based rates. These concerns generally include how the Commission determines product and geographic markets, and the standards used to determine whether sellers can exercise market power. In response to these concerns, as noted above public utility owners of new capacity must still seek case-by-case approval before they can sell power from new capacity at market-based rates and, as stated in the Final Rule, intervenors may present specific evidence that a seller requesting such market rates possesses generation dominance or otherwise has market power.[13] These requirements include considerations of transmission market power, whether other barriers to entry exist and whether there is evidence of affiliate abuse or reciprocal dealing.

b. Market-based Rates for Existing Generation

In the Final Rule, the Commission found that there is not enough evidence on the record to make a generic determination about whether market power may exist for sales from existing generation.[14] The Commission indicated that it would continue its case-by-case approach that allows market-based rates based on an analysis of generation market power in first tier and second tier markets.[15] The Commission further indicated that while it will continue to apply the first-tier/second-tier analysis, it will allow applicants and intervenors to challenge the presumption implicit in the Commission's practice that the relevant geographic market is bounded by the second-tier utilities. Finally, the Commission stated that it would maintain its current practice of allowing market-based rates for existing generation to go into effect not subject to refund.[16] To the extent that either the applicant or an intervenor in individual cases offers specific evidence that the relevant geographic market ought to be defined differently than under the existing test, the Commission indicated that it will examine such arguments through formal or paper hearings.

Rehearing Requests

No rehearing requests were filed with respect to this matter.

4. Merger Policy

In the Final Rule, the Commission explained that it had issued a Notice of Inquiry (NOI) on the Commission's merger policy in Docket No. RM96–6–000.[17] The Commission indicated that it will review whether its criteria and policies for evaluating mergers need to be modified in light of the changing circumstances, including the Final Rule, that are occurring in the electric industry. The Commission concluded that it would review its merger policy in the ongoing NOI proceeding.[18]

Rehearing Requests

No rehearing requests were filed with respect to this matter.

Commission Conclusion

We note that on December 18, 1996, the Commission issued, in the NOI proceeding, a Policy Statement that updates and clarifies the Commission's procedures, criteria and policies concerning public utility mergers.[19]

5. Contract Reform

Requirements and Transmission Contracts

In the Final Rule, the Commission concluded that it was not appropriate to order generic abrogation of existing requirements and transmission contracts, but concluded nonetheless that the modification of certain requirements contracts (those executed on or before July 11, 1994) on a case-by-case basis may be appropriate.[20] The Commission further concluded that, even if customers under such requirements contracts are bound by so-called *Mobile-Sierra* clauses, they ought to have the opportunity to demonstrate that their contracts no longer are just and reasonable.

The Commission found that it would be against the public interest to permit a *Mobile-Sierra* clause in an existing wholesale requirements contract[21] to preclude the parties to such a contract from the opportunity to realize the benefits of the competitive wholesale power markets. Thus, it explained, a party to a requirements contract containing a *Mobile-Sierra* clause no longer will have the burden of establishing independently that it is in the public interest to permit the modification of such contract. The party, however, still will have the burden of establishing that such contract no longer is just and reasonable and therefore ought to be modified.

The Commission explained that this finding complements the Commission's finding that, notwithstanding a *Mobile-Sierra* clause in an existing requirements contract, it is in the public interest to permit amendments to add stranded cost provisions to such contracts if the public utility proposing the amendment can meet the evidentiary requirements of the Final Rule. Accordingly, the Commission required that any contract modification approved under this Section must provide for the utility's recovery of any costs stranded consistent with the contract modification. Further, the Commission concluded that if a customer is permitted to argue for modification of existing contracts that are less favorable to it than other generation alternatives, then the utility should be able to seek modification of contracts that may be beneficial to the customer.

Coordination Agreements

The Commission concluded that to assure that non-discriminatory open access becomes a reality in the relatively near future, it was necessary to modify existing economy energy coordination agreements. The Commission stated that it would condition future sales and

[13] We do not agree with entities that claim that our decision to rely on evidence raised by intervenors in particular cases with respect to transmission constraints improperly shifts the burden away from the utility, which has the greatest access to information concerning those constraints. Given that we have yet to see any evidence of generation dominance in long-term bulk power markets we do not believe that it is appropriate to burden all market-based rate applicants with significant information requirements as an initial matter. However, if an intervenor raises a specific factual concern with respect to a transmission constraint that may result in the exercise of market power in a particular case, we will examine those facts in a paper or formal hearing. In that context, the utility would be required to come forward with information sufficient to permit a full examination of the effect of the constraint on the applicant's ability to exercise market power.

[14] FERC Stats. & Regs. at 31,660; *mimeo* at 73–75.

[15] *See, e.g.*, Southwestern Public Service Company, 72 FERC ¶ 61,208 at 61,996 (1995), *reh'g pending*.

[16] The Final Rule contained a typographical error in which the word ''not'' was erroneously omitted.

[17] FERC Stats. & Regs. ¶ 35,531 (1996).

[18] FERC Stats. & Regs. at 31,661; *mimeo* at 77–78.

[19] Order No. 592, Policy Statement Establishing Factors the Commission will Consider in Evaluating Whether a Proposed Merger is Consistent with the Public Interest, 77 FERC ¶ 61,263 (1996).

[20] FERC Stats. & Regs. at 31,663–66; *mimeo* at 84–92.

[21] The Commission defined these as contracts executed on or before July 11, 1994.

purchase transactions under existing economy energy coordination agreements [22] to require that the transmission service associated with those transactions be provided pursuant to the Final Rule's requirements of non-discriminatory open access, no later than December 31, 1996. The Commission also required that, for new economy energy coordination agreements [23] where the transmission owner uses its transmission system to make economy energy sales or purchases, the transmission owner must take such service under its own transmission tariff as of the date trading begins under the agreement.[24]

Finally, the Commission concluded that it would not require the modification of non-economy energy coordination agreements. However, the Commission noted that this does not insulate such agreements from complaints that transmission service provided under such agreements should be provided pursuant to the Final Rule pro forma tariff.

Rehearing Requests

Various utilities oppose the Commission's finding that it is in the public interest to permit the modification of existing requirements contracts that contain *Mobile-Sierra* clauses. On the other hand, a number of customers assert that the Commission did not go far enough and seek enhanced contract reformation rights.

Utilities Against Contract Reformation

Several utilities argue that the Commission's finding is not supported by substantial evidence.[25] Utilities For Improved Transition asserts that the Commission cannot rely on economic theory as a substitute for substantial evidence.[26] It argues that the record in this proceeding demonstrates that the marketplace is becoming increasingly competitive without mandatory tariffs, which is evidence of market health, not market problems. It further argues that even if undue discrimination is proven, the remedy is not needed because the record shows that existing programs are meeting the industry's needs.

Southwestern argues that the Commission has improperly chosen to ignore the public interest standard and has failed to make the contract specific analysis here that it performed in *Northeast Utils. Serv. Co.*, 66 FERC ¶ 61,332 (1994), *aff'd*, 55 F.3d 686 (1st Cir. 1995). PSE&G and Carolina P&L also argue that the Commission failed to demonstrate the ''unequivocal public necessity'' for generically abrogating the *Mobile-Sierra* clauses and assert that the Commission has presented no evidence as to how the public interest will be served by abrogating these contracts. PSE&G and Carolina P&L further argue that the Commission cannot avoid making a public interest determination ''by the simple expedient of asserting that the public interest requires it to ignore the *Mobile-Sierra* clauses that required that public-interest determination in the first place.'' [27]

Union Electric and PSE&G argue that the Commission, in justifying its public interest finding, inappropriately focused on the interests of the parties to the contract instead of on whether non-parties will be adversely affected by the existing contracts.

Public Service Co of CO asserts that the Commission should clarify the definition of requirements contract to include long-term block purchases of electricity. It states that it purchases a large percentage of its system requirements under long-term block purchase agreements, and that under the Commission's abrogation policy in Order No. 888, its ability to abrogate these supply arrangements would be treated differently because its contracts do not meet the definition of a ''wholesale requirements contract,'' as defined in new section 35.26(b)(1) of the Commission's Regulations. Public Service Co of CO further asserts that the Commission has not adequately explained why it is appropriate or in the public interest to allow partial requirements customers to abrogate their contracts, but not similarly to allow a public utility to abrogate its supply arrangements.[28]

PSE&G and Carolina argue that the availability of stranded cost recovery cannot support allowing customers to modify rates under *Mobile-Sierra* clauses that required that public-interest determination in the first place.

PSE&G and Carolina P&L also argue that no *Mobile-Sierra* contracts entered into after October 24, 1992 (the date EPAct became law) should be subject to the Rule because since that date customers have been able to apply for an order under section 211 to have power transmitted to them from suppliers other than the utility to whom they are interconnected.

PSE&G requests that the Commission clarify that the just and reasonable standard used in considering a contract abrogation claim will be limited to a determination of whether the rate is just and reasonable within the cost-based zone of reasonableness of the selling public utility. Such an analysis, PSE&G asserts, should not include a comparison to what other utilities offer to their customers.[29]

Customers Seek Enhanced Contract Reformation Rights

TAPS argues that the Commission should apply a just and reasonable standard to requests by all ''victims'' of undue discrimination to seek modifications of requirements or transmission contracts, whether they are subject to *Mobile-Sierra* or not. On the other hand, TAPS asserts that utilities should be bound to the bargain they extracted from transmission customers. Wisconsin Municipals request that the Commission clarify that parties may seek mandatory abrogation of preexisting transmission contracts or provisions and that the Commission will apply a rebuttable presumption that terms and conditions inferior to the pro forma tariff are unjust and unreasonable on their face.

CCEM argues that requirements customers should receive blanket conversion rights. At a minimum, CCEM asserts, if a customer seeks conversion, the burden of proof in the proceeding should shift to the utility. CCEM also emphasizes that the question remains why conversion was deemed essential in natural gas markets, but not in the transition to competition in the electric industry.

Blue Ridge argues:

> In neither the power supply nor transmission access case should a provider be allowed to modify existing power supply contracts under any but the *Mobile Sierra* public interest burden of proof. In both the power supply or transmission access cases, the Commission should articulate the suggested standards for what constitutes a *prima facia* case. [[30]]

Commission Conclusion

Before responding to the rehearing arguments raised, we wish to clarify our *Mobile-Sierra* findings. We explained in Order No. 888 that we were making two

[22] The Commission defined ''existing'' as those agreements executed prior to 60 days after publication of the Final Rule in the FEDERAL REGISTER.

[23] The Commission defined ''new'' as those agreements executed 60 days after publication of the Final Rule in the FEDERAL REGISTER.

[24] Accordingly, the Commission explained, transmission service needed for sales or purchases under all new economy energy coordination agreements will be pursuant to the Final Rule pro forma tariff.

[25] Utilities For Improved Transition, Union Electric, PSE&G, Carolina P&L.

[26] Union Electric adds that there is no evidence that any existing economy energy coordination agreements are unduly discriminatory and require modification.

[27] PSE&G at 6.

[28] *See* also PSE&G.

[29] *See* also Carolina P&L.

[30] Blue Ridge at 16.

complementary public interest findings. First, as discussed further in Section IV.J, we found that it is in the public interest to permit public utilities to seek stranded cost amendments to existing requirements contracts with *Mobile-Sierra* clauses. Second, we found that a ''party'' to a requirements contract containing a *Mobile-Sierra* clause no longer will have the burden of establishing independently that it is in the public interest to permit the modification of such contract, but still will have the burden of establishing that such contract no longer is just and reasonable and therefore ought to be modified. We clarify that, in making this second finding, our reference to a ''party'' to a requirements contract containing a *Mobile-Sierra* clause was directed at modification of contract provisions by *customers.* [31] Additionally, it applies to any contract revisions sought, whether or not they relate to stranded costs. [32]

In response to the *Mobile-Sierra* rehearing arguments described above, as well as the *Mobile-Sierra* arguments described in Section IV.J concerning our determinations regarding stranded cost amendments to contracts, the Commission believes it is important to first address the general context in which our *Mobile-Sierra* determinations have been made. In Order No. 888, the Commission removed the single largest barrier to the development of competitive wholesale power markets by requiring non-discriminatory open access transmission as a remedy for undue discrimination. This action carries with it the regulatory public interest responsibility to address the difficult transition issues that arise in moving from a monopoly, cost-based electric utility industry to an industry that is driven by competition among wholesale power suppliers and increasing reliance on market-based generation rates.

There are two predominant, overlapping transition issues that arise as a result of our actions in this rulemaking: first, how to deal with the uneconomic sunk costs incurred, and second, how to deal with the contracts that were entered into, under an industry regime that rested on a regulatory framework and set of expectations that are being fundamentally altered. To address these issues, the Commission has balanced a number of important interests in order to achieve what it believes will be a fair and orderly transition to competitive markets. These interests include the financial stability of the electric utility industry and permitting customers to obtain the benefits of competitive markets without undue disruption or unfairness to other customers or industry participants.

As the above rehearing arguments demonstrate, there is no consensus on how the Commission should manage the transition. In fact, parties offer diverse and conflicting views as to what the Commission should do regarding existing contracts. Some would have us let all contracts run their course with no opportunity for customers to modify or terminate their contracts, no matter how long the contracts or how onerous their terms. Others advocate automatic generic abrogation of all contracts. Yet others want a guaranteed automatic right to renew a contract if it happens to contain favorable rates and terms.[33]

Rather than adopting one extreme position or the other, the Commission has taken a measured approach with regard to contract modification, including modification of contracts that contain *Mobile-Sierra* clauses. Our goal is to balance the desire to honor existing contractual arrangements with the need to provide some means to accelerate the opportunity of parties to participate in competitive markets. To accomplish this balance, the Commission, first, has made *Mobile-Sierra* public interest findings (discussed further below) only as to a limited set of contracts: those wholesale requirements contracts executed on or before July 11, 1994, which is the date of our first stranded cost proposed rulemaking and which served to put the industry and customers on notice that future contracts should explicitly address the rights, obligations and expectations of parties, including stranded cost obligations.[34]

Second, with regard to contract modifications sought by utilities, as discussed in more detail in Section IV.J, utilities that seek to add stranded cost provisions have a high evidentiary burden to meet before they can add contract provisions that permit stranded cost recovery beyond the end of their contract terms; the burden is particularly high in the case of contracts with notice provisions. With regard to modifications of contract provisions that do not relate to stranded costs, a utility with a *Mobile-Sierra* contract clause will have the burden of showing that the provisions are contrary to the public interest.[35]

Third, with regard to contract modifications sought by customers, a customer will have to show that the provisions it seeks to modify are no longer just and reasonable.[36] If a customer seeks to shorten or eliminate the term of an existing contract, any contract modification approved by the Commission will take into account the issue of appropriate stranded cost recovery by the customer's supplying utility.

In permitting customers the *opportunity* to seek these types of modifications, even for contracts that contain *Mobile-Sierra* clauses, the Commission has based its public interest findings on the unprecedented industry changes facing utilities and their customers. While, as we stated in the Final Rule, there is no market failure in the electric industry that would justify generic abrogation of existing contracts, nevertheless the industry is in the midst of fundamental change. We cannot conclude that it is in the public interest to require all customers to be

[31] We note that the fact that a contract may bind a utility to a *Mobile-Sierra* public interest standard does not necessarily mean that the customer is also bound to that standard. Unless a customer specifically waives its section 206 just and reasonable rights, the Commission construes the issue in favor of the customer. *See* Papago Tribal Utility Authority v. FERC, 723 F.2d 950, 954 (D.C. Cir. 1983).

[32] In situations in which a customer institutes a section 206 proceeding to modify a contract that binds the utility to a *Mobile-Sierra* public interest standard, the utility may make whatever arguments it wants regarding any of the contract terms, including those unrelated to stranded costs, but will be bound to a *Mobile-Sierra* public interest standard for contract terms that do not relate to stranded costs.

[33] Similarly, as discussed in Section IV.J, parties have taken extreme positions as to stranded cost recovery.

[34] As to existing economy energy coordination agreements, the Commission concludes that the evidence also supports its decision to condition future sales and purchase transactions that may occur under the ongoing umbrella coordination agreements. Specifically, we are requiring that the transmission service associated with these future transactions be provided pursuant to the Final Rule pro forma tariff. *See* Public Service Electric & Gas Company, 78 FERC ¶ 61,119, slip op. at 4 and n.7 (1997).

[35] As discussed below, pre-July 11, 1994 contracts were entered into during an era in which transmission providers exerted monopoly control over access to their transmission facilities. The unequal bargaining power between utilities and captive customers is the basis for our determination that utilities that have pre-July 11 *Mobile-Sierra* requirements contracts will have to satisfy the public interest standard in order to effectuate any non-stranded cost change to the contract, but that customers to such contracts will be able to effectuate any change by satisfying a just and reasonable standard.

[36] We will not grant the request by PSE&G and Carolina P&L that the just and reasonable standard will be limited to a determination of whether the rate is just and reasonable within the cost-based zone of reasonableness of the selling utility and should not include a comparison to what other utilities offer their customers. Because stranded costs will be taken into account when customers seek contract termination or modification, it would not be appropriate to limit customers in the evidence they may present.

held to requirements contracts that were executed under the prior industry regime, no matter what the circumstances of those contracts.

In response to parties who challenge the Commission's finding that it would be against the public interest to deny customers an opportunity to seek modification of wholesale requirements contracts executed on or before July 11, 1994,[37] these parties ignore the fact that these contracts were entered into during an era in which transmission providers exercised monopoly control over access to their transmission facilities.[38] The majority of customers under these types of contracts were captive, *i.e.*, they had no realistic choice but to purchase generation from their local utility because they had no transmission to reach another supplier. Many of these contracts were the result of uneven bargaining power between customers and monopolist transmission providers.[39] While monopolist transmission providers may not have exercised monopoly power in all situations,[40] the unprecedented competitive changes that have occurred (and are continuing to occur) in the industry may render their contracts to be no longer in the public interest or just and reasonable. These changed circumstances, discussed at length in the Final Rule, and the further changes that will occur as a result of open access transmission, may affect whether such contracts continue to be just and reasonable or not unduly discriminatory both as to the direct customers of the contracts, as well as to indirect, third-party consumers as well.[41]

We therefore reject arguments that there is no ''evidence'' to support our finding that it is in the public interest to permit review of these contracts in light of the specific circumstances surrounding the contracts and in light of dramatically changed industry circumstances. We emphasize, however, that our decision is to permit an *opportunity* for review and that we will require a case-by-case showing that any modifications should be permitted. [42] As we explained in the Final Rule, this decision complements our decision that it is in the public interest to permit amendments to add stranded cost provisions to existing contracts if case-by-case evidentiary burdens are met.

As we discuss further in our detailed stranded cost discussion in Section IV.J, we do not interpret the *Mobile-Sierra* public interest standard as practically insurmountable [43] in the extraordinary situation before us where historic statutory and regulatory changes have converged to fundamentally change the obligations of utilities and the markets in which both they and their customers will operate. The ability to meet our overarching public interest responsibilities and to protect consumers would be virtually precluded if we were to apply a practically insurmountable standard of review before taking into account these fundamental industry-wide changes.[44]

With respect to Public Service Co of CO's argument, we disagree that the definition of a wholesale requirements contract should be modified to include a long-term block purchase of electricity. In the majority of circumstances, such long-term supply contracts are voluntary arrangements in which neither party had market power. It would be inappropriate to make generic *Mobile-Sierra* findings as to these types of contracts. Parties can avail themselves of the section 205 and 206 procedures already available to them if they want to seek modification of such contracts.

Finally, we reject CCEM's argument that all customers should receive automatic conversion rights because customers were provided such a right in the restructuring of the natural gas industry. We have taken, as is within our discretion, a substantially different approach here from that taken when we restructured the natural gas industry. As we stated in the Final Rule, and as alluded to above, at the time the Commission addressed this situation in the natural gas industry it was faced with shrinking natural gas markets, statutory escalations in natural gas ceiling prices under the Natural Gas Policy Act, and increased production of gas.[45] Moreover, the natural gas industry was plagued with escalating take-or-pay liabilities.

There was a market failure in the natural gas industry that required the

[37] We note that some of the very parties making this challenge either do not object to the Commission's *Mobile-Sierra* findings permitting utilities to add stranded cost amendments to their contracts, or ask the Commission to broaden even further the scope of extra-contractual stranded cost recovery under the rule.

[38] We also reject arguments that a remedy is not needed because existing programs, *i.e.*, those prior to Order No. 888, are meeting the needs of the industry. This very rulemaking, with the substantial comments filed by entities pointing out the failures of the current system and the need for change, and the extensive restructurings and state-initiated open access programs occurring around the country, on their face, refute these arguments.

[39] It is also clear from the number of entities filing comments on the NOPR and rehearing requests of the Final Rule that many entities believe that their contracts were the result of uneven bargaining power and that they should be provided the opportunity to seek to terminate their existing contracts.

[40] In an era that was not characterized by competition in the generation sector, the Commission's response was to ensure that the rates for such contracts were no higher than the seller's cost (including a reasonable return on equity). In this way, the Commission sought to limit the seller's ability to reap the benefits of the seller's monopoly position.

[41] See FPC v. Sierra Pacific Power Company, 350 U.S. 348, 355 (1956); Northeast Utilities Service Company, 66 FERC ¶ 61,332 (1994), *aff'd*, 55 F.3d 686, 691 (1st Cir. 1995); Mississippi Industries v. FERC, 808 F.2d 1525, 1553 (D.C. Cir. 1987).

[42] We will not exclude *Mobile-Sierra* contracts entered into after the effective date of EPAct, as argued by PSE&G and Carolina P&L. As we explained in the Final Rule, there are significant time delays associated with section 211 proceedings. Accordingly, the availability of a section 211 proceeding cannot substitute for readily available service under a filed non-discriminatory open access tariff. FERC Stats. & Regs. at 31,646; *mimeo* at 35. We do not believe that EPAct created the expectation of open access on such a broad scale that we can assume that parties no longer generally expected ''business as usual'' to continue, and we will not presume that the exercise of market power was not at work when *Mobile-Sierra* contracts were entered into after EPAct. We also note that these arguments are similar to those proffered by opponents of stranded cost recovery, who argue that after EPAct utilities had no reasonable expectation of continuing to serve customers beyond the terms of existing contracts. In this context as well, we will not presume that, after EPAct, utilities could have no reasonable expectation of continuing to serve a customer beyond the contract term.

[43] As the D.C. Circuit explained in *Papago Tribal Utility Authority v. FERC*, 723 F.2d 950 (D.C. Cir. 1983) (Papago), there are essentially three contractual arrangements for rate revision: (1) the parties agree that the utility may file new rates under section 205, subject to the just and reasonable standard of review; (2) the parties agree to eliminate the utility's right to file rates under section 205 and the Commission's right to change pre-existing rates under section 206's just and reasonable standard (leaving the Commission's indefeasible right to change pre-existing rates that are contrary to the public interest); and (3) the parties agree to eliminate the utility's right to file new rates under section 205, but leave unaffected the Commission's power to change pre-existing rates under section 206's just and reasonable standard of review. 723 F.2d at 953. The same contractual arrangements also would apply to non-rate terms and conditions. We here address those contractual arrangements that eliminate the rights of one or both parties to modify a contract under the just and reasonable standard. We note that the Commission always has the indefeasible right under section 206 to change rates, terms or conditions that are contrary to the public interest. 723 F.2d at 953–55; see also Florida Power & Light Company, 67 FERC ¶ 61,141 at 61,398 (1994) *appeal dismissed*, No. 94–1483 (D.C. Cir. July 27, 1995) (unpublished); Southern Company Services, Inc., 67 FERC ¶ 61,080 at 61,227–28 (1994); Mississippi Industries v. FERC, 808 F.2d 1525, 1552 n.112.

[44] We reject the arguments of PSE&G and Carolina P&L that we have failed to demonstrate the ''unequivocal public necessity'' for generically ''abrogating'' *Mobile-Sierra* clauses and that we have presented no evidence as to how the public interest will be served by abrogating these contracts. We have concluded that there is a public necessity to permit the *opportunity* to seek contract changes in light of fundamental industry changes. However, we have not abrogated any contracts by this Rule.

[45] FERC Stats. & Regs. at 31,664; *mimeo* at 84.

extraordinary measure of generically allowing all customers to break their contracts with pipelines. In contrast, market circumstances in the electric industry today do not compel generic abrogation of contracts. The more moderate approach we have taken will permit us to take into account the fundamental industry changes that have occurred (and will continue to occur), to balance the interests of all affected parties, and to help avoid drastic shocks to industry participants.

Right of First Refusal

In the Final Rule, the Commission concluded that all firm transmission customers (requirements and transmission-only), upon the expiration of their contracts or at the time their contracts become subject to renewal or rollover, should have the right to continue to take transmission service from their existing transmission provider.[46] If not enough capacity is available to meet all requests for service, the right of first refusal gives the existing customer who had contractually been using the capacity on a long-term, firm basis the option of keeping the capacity. However, the limitations imposed by the Commission are that the underlying contract must have been for a term of one-year or more and the existing customer must agree to match the rate offered by another potential customer, up to the transmission provider's maximum filed transmission rate at that time, and to accept a contract term at least as long as that offered by the potential customer.[47] Moreover, the Commission indicated that this right of first refusal is an ongoing right that may be exercised at the end of all firm contract terms (including all future unbundled transmission contracts).

Requests for Rehearing

On rehearing, most petitioners agree with or do not contest the notion of providing existing transmission customers with a right of first refusal, but many have requested modification or clarification of the Commission-imposed limitations on such a right. A variety of transmission customers assert that the Commission's right of first refusal provision fails to adequately protect existing transmission customers' rights to continued service and seek changes to the Commission's provision. On the other hand, a number of utilities believe that the Commission should provide additional restrictions on the right of first refusal.

Customers' Positions

APPA argues that (1) existing customers should only have to agree to service that matches the term of any power supply contract for which it will use the transmission arrangement or, in the absence of a generation contract, one year, and (2) the pricing provision should be changed to reflect the current just and reasonable rate, as approved by the Commission, for similar transmission service.

NRECA also argues that the term and pricing provisions of section 2.2 need to be changed. With respect to the term of the contract the customer should be required to match, NRECA asserts that it should be one year, which corresponds to the definition of long-term firm service in the tariff. With respect to the rate, NRECA requests that the Commission cap the obligation to match the price offered by another customer at the maximum transmission rate the incumbent customer is obligated to pay to the transmission provider at the close of the prior contract term.

TDU Systems argue that the right of first refusal provision fails to take into consideration amounts that TDUs have contributed to the development of the transmission systems through prior transmission rates. TDU Systems are concerned about the possibility of an increase in the price of transmission capped only by the cost of increasing the capacity of the provider's transmission system.

TAPS requests that the Commission clarify that the transmission provider may only charge its then effective rates for existing, non-constrained transmission capacity because to allow opportunity or expansion costs would perpetually put the existing transmission customers on the margin at the end of their contract terms subjecting them to higher rates than the transmission provider.[48]

Blue Ridge raises a possible discrepancy between the language in the tariff and the language in the preamble. It asserts that section 2.2 ''requires the existing customer to 'pay the current just and reasonable rate, as approved by the Commission,' while the Regulatory Preamble requires the customer to 'match the rate offered by another potential customer, up to the transmission provider's maximum filed transmission rate at that time.' Order No. 888, *mimeo* at 88.''

Tallahassee asks the Commission to clarify that the right of first refusal to presently bundled transmission capacity accrues to the power customer paying the bundled rate and not to the intermediary acting on behalf of the customer.

AEC & SMEPA maintain that the price and term limitations of section 2.2 would place TDUs at a competitive disadvantage vis-a-vis the transmission provider by subjecting TDUs to incremental costs, including the costs of system upgrades, if other new customers are vying to use the transmission system. They state that the Commission must provide existing transmission customers the same rights as the transmission provider's other native load customers.

Utilities' Positions

PSNM argues that imposing a right of first refusal is inconsistent with the Commission's finding that contracts should not be abrogated. In effect, it argues that imposition of the right of first refusal abrogates existing contracts executed with the expectation that capacity could be recalled for the utility's own use upon expiration of the contracts. PSNM explains that it has a constrained transmission system and has been balancing specific contract durations against projected future native loads so that required capacity may be made available for use by third parties in the short-term, but not be committed to those parties at the time it is needed to be recalled. Moreover, PSNM asserts that Order No. 888 is not supported by the right of first refusal process of Order No. 636 because the Commission does not have abandonment authority under the FPA and its authority to require continuation of service is not well-defined and is controversial.[49]

Utilities For Improved Transition and Florida Power Corp argue that section 2.2 of the pro forma tariff should be modified by ''restricting rollover rights to the same points of receipt and delivery as the terminating service and

[46] FERC Stats. & Regs. at 31,665; *mimeo* at 88.

[47] The Commission explained that this right of first refusal exists whether or not the customer buys power from the historical utility supplier or another power supplier. If the customer chooses a new power supplier and this substantially changes the location or direction of its power flows, the customer's right to continue taking transmission service from its existing transmission provider may be affected by transmission constraints associated with the change.

[48] *See also* AEC & SMEPA.

[49] All transmission contracts with public utility transmitters can only be terminated by a filing with the Commission under FPA section 205. Thus, the Commission has interpreted its section 205 authority as permitting it to suspend termination of service for 5 months beyond the expiration of a contract's term if such action is necessary to protect ratepayers. *See, e.g.*, Kentucky Utilities Company, 67 FERC ¶ 61,189 at 61,573 (1994). (While the termination procedures for power sales contracts executed after July 9, 1996 were modified in Order No. 888, there were no changes regarding termination procedures for transmission contracts.).

by providing the customer notice of a competing application and 90 days in which to file its own application for service for a term at least as long as the competing application.'' (Florida Power Corp at 11–13; Utilities For Improved Transition at 50–53). Similarly, EEI argues that to obtain a priority for continuation of service, customers must be seeking service that is substantially similar to or a continuation of the service they already receive and must be subject to a time limit on the reservation priority. CSW Operating Companies assert that it is unclear how the right of first refusal provision will be implemented.

State Commission Position

VT DPS states that the right of first refusal provision offers inadequate protection: ''While it is true that the existing customer could secure a five year transmission arrangement under a *new* contract, its right to *continuous* service is placed in jeopardy if it does not match the six year offer of the competing bidder.'' VT DPS argues that the Commission's bare bones provision opens the opportunity for competitive mischief by the transmission provider. VT DPS proposes that ''the existing customer should be able to renew its contract by matching the highest transmission price offered in the marketplace (up to the tariff maximum rate) and by offering to extend its contract for seven years or the prevailing length of firm transmission contracts in the marketplace, whichever is shorter.'' (VT DPS at 17–21).

Commission Conclusion

In this order, the Commission reaffirms its decision to give a reservation priority to existing and future firm transmission customers served under a contract of one year or more, and also addresses petitioner arguments regarding the Commission-imposed limitations associated with the exercise of that priority.

Rationale

Our policy rationale for giving an existing firm transmission customer (requirements and transmission-only),[50] served under a contract of one year or more, a reservation priority (right of first refusal) when its contract expires is that it provides a mechanism for allocating transmission capacity when there is insufficient capacity to accommodate all requestors. If there are capacity limitations and both customers (existing and potential) are willing to pay for firm transmission service of the same duration, the right of first refusal provides a tie-breaking mechanism that gives priority to existing customers so that they may continue to receive transmission service.[51]

Contract Term Limitation

We reject arguments to modify the requirement in section 2.2 that existing long-term firm transmission customers seeking to exercise their right of first refusal must agree to a contract term at least as long as that sought by a potential customer. The objective of a right of first refusal is to allow an existing firm transmission customer to continue to receive transmission service under terms that are just, reasonable, not unduly discriminatory, or preferential. Absent the requirement that the customer match the contract term of a competing request, utilities could be forced to enter into shorter-term arrangements that could be detrimental from both an operational standpoint (system planning) and a financial standpoint.

Rate Limitation

We also reject the proposition that either existing wholesale customers or transmission providers providing service to retail native load customers should be insulated from the possibility of having to pay an increased rate for transmission in the future. The fact that existing customers historically have been served under a particular rate design does not serve to ''grandfather'' that rate methodology in perpetuity. Because the purpose of the right of first refusal provision is to be a tie-breaker, the competing requests should be substantially the same in all respects.[52]

In response to Blue Ridge's concern regarding a discrepancy between the language in section 2.2 of the tariff and the preamble, we clarify that existing customers who exercise their right of first refusal will be required to pay the just and reasonable rate, as approved by the Commission at the time that their contract ends.[53]

Mechanics of the Right of First Refusal Process

CSW Operating Companies asked the Commission to clarify the mechanics of exercising the right of first refusal. We have determined not to specify in this order the mechanics by which the right of first refusal mechanism will be exercised for existing firm transmission arrangements. Instead, we intend to address such issues on a case-by-case basis, if and when a dispute arises. However, we encourage utilities and their customers to include specific procedures for exercising the right of first refusal in future transmission service agreements executed under the pro forma tariff. And of course, utilities are free to make section 205 filings to propose additions to the pro forma tariff to generically specify procedures for dealing with the issues.

Existing Contracts

By providing existing customers a right of first refusal, we are not, as PSNM claims, abrogating contracts. Moreover, PSNM's concern that the right of first refusal will prohibit utilities from ''recalling'' existing capacity to meet native load growth that was anticipated at the time existing third-party transmission contracts were executed can be addressed in the context of a specific filing by a utility demonstrating that it had no reasonable expectation of continuing to provide transmission service to the wholesale transmission customer at the end of its contract. For future transmission contracts, Order No. 888 permits utilities to reserve existing transmission capacity to serve the needs (current and reasonably forecasted) of its existing native load (retail) customers. Moreover, if a utility provides firm transmission service to a third party for a time until native load needs the capacity, it should specify in the contract that the right of first refusal does not apply to that firm service due to a reasonably forecasted need at the time the contract is executed.

Informational Filings

With respect to all existing requirements contracts and tariffs that provide for bundled rates, the Commission, in the Final Rule, required all public utilities to make informational

[50] We clarify that we did not intend the term ''all firm transmission customers'' to include only requirements and transmission-only customers, but intended that it include all bundled firm customers as well.

[51] We reject Tallahassee's argument that the right of first refusal should accrue to the power customer paying the bundled rate and not to any intermediary acting on its behalf. Our right of first refusal mechanism is simply a tie-breaker that gives priority to existing firm transmission customers.

[52] The proposal to restrict the right of first refusal provision to exactly the same points of receipt and delivery as the terminating service would competitively disadvantage existing customers seeking new sources of generation. However, as we stated in Order No. 888, if the customer chooses a new power supplier and this substantially changes the location or direction of the power flows it imposes on the transmission provider's system, the customer's right to continue taking transmission service from its existing transmission provider may be affected by transmission constraints associated with the change. FERC Stats. & Regs. at 31,666 n.176; *mimeo* at 89 n.176.

[53] As Order No. 888 indicates, they may be required to pay the transmission provider's *maximum* transmission rate.

filings setting forth the unbundled power and transmission rates reflected in those contracts and tariffs.[54]

Requests for Rehearing

Utilities For Improved Transition and VEPCO ask the Commission to clarify whether the unbundled transmission rate should be the current transmission tariff rate (bundled rate likely not to include the current price for transmission service) or an approximation of the rate at the time the contract was executed (may be impossible to determine).

Commission Conclusion

We previously addressed the determination of the unbundled transmission rate in informational filings in an order issued October 16, 1996.[55] In that order, we noted that Order No. 888 does not prescribe any specific method for calculating separately-stated transmission and generation rates and public utilities have used different methods in their informational filings. Because of the general lack of controversy over the informational filings and the fact that they are for informational purposes as a benefit to existing customers, the Commission accepted the vast majority of the informational filings. The Commission added, however, that it did not consider the informational rates binding for any future transactions. Accordingly, we need not now prescribe a specific method to calculate the unbundled transmission rate included in informational filings.

Existing Contracts

In the Final Rule, the Commission explained that because it was not abrogating existing requirements and transmission contracts generically and because the functional unbundling requirement applies only to new wholesale services, the terms and conditions of the Final Rule pro forma tariff do not apply to service under existing requirements contracts.[56]

Rehearing Requests

San Francisco asks that the Commission clarify that nothing in Order No. 888 is intended to affect prices, or price-setting methodologies, in existing contracts.

Commission Conclusion

By order issued July 2, 1996, we clarified that

> the filing of an open access compliance tariff on or before July 9, 1996 does not supersede an existing transmission agreement that has been accepted by the Commission unless specifically permitted in the agreement on file. If a utility seeks to modify or terminate an existing transmission agreement, it must separately file to modify or terminate such contracts under appropriate procedures under section 205 or 206 of the Federal Power Act, consistent with the terms of its contract.[57]

Thus, nothing in Order No. 888 affects prices or price-setting methodologies in existing contracts, unless specifically permitted in the contract on file.

6. Flow-based Contracting and Pricing

In Order No. 888, the Commission explained that it would not, at that time, require that flow-based pricing and contracting be used in the electric industry.[58] It recognized that there may be difficulties in using a traditional contract path approach in a non-discriminatory open access transmission environment. At the same time, however, the Commission noted that contract path pricing and contracting is the longstanding approach used in the electric industry and it is the approach familiar to all participants in the industry. Thus, the Commission was concerned that to require a dramatic overhaul of the traditional approach—such as a shift to some form of flow-based pricing and contracting—could severely slow, if not derail for some time, the move to open access and more competitive wholesale bulk power markets. In addition, the Commission indicated its belief that it would be premature to impose generically a new pricing regime without the benefit of any experience with such pricing. Accordingly, the Commission welcomed new and innovative proposals, but determined not to impose some form of flow-based pricing or contracting in the Final Rule.

Rehearing Requests

American Forest & Paper argues that contract path pricing should be prohibited. American Forest & Paper asserts that QFs and other independents are being forced by contract path wheeling utilities to indemnify them from liability for third-party claims of inadvertent flow costs resulting from the transaction, while paying postage stamp rates for the entire amount of contracted transmission. American Forest & Paper supports an average postage stamp rate by region, with the utilities within the region agreeing on a way to divide up the rate appropriately.

Commission Conclusion

As the Commission explained in the Final Rule, we are concerned that a dramatic overhaul of the traditional contract path approach could slow or derail the move to open access and, in any event, is premature without the benefit of any experience with alternative pricing regimes. The Commission, however, welcomes new and innovative proposals from the industry. American Forest & Paper has not presented a case-specific proposal of any detail that would provide the Commission and interested parties the opportunity to test the appropriateness of a change from the contract path approach. Until the Commission has such an opportunity, we are not prepared to change generically the traditional contract path approach with which the electric industry is so familiar.

Moreover, American Forest & Paper's proposal to prohibit contract path pricing and mandate regional postage-stamp rates would be inconsistent with the rate flexibility that the Commission provided in the Transmission Pricing Policy Statement and embraced in the Final Rule.

B. Legal Authority

In the Final Rule, the Commission responded to commenters challenging the Commission's authority to require open access and reaffirmed its conclusion in the NOPR that it has the authority under the FPA to order wholesale transmission services in interstate commerce to remedy undue discrimination by public utilities.[59]

Rehearing Requests

Authority To Order Open Access Tariffs

Union Electric challenges the Commission's authority to require wheeling based on arguments that: (1) the Rule overlooks the fact that the *AGD* case[60] pertained to voluntary actions by the pipelines and the Commission's imposition of open access requirements as a condition on permitting the desired authorizations; (2) the Commission incorrectly treats the *Otter Tail* case;[61] (3) the legislative histories of the NGA and FPA are different and the legislative history of the FPA does not support the Commission's authority to order wheeling; (4) the Commission made prior contrary statements to the U.S.

[54] FERC Stats. & Regs. at 31,665–66; *mimeo* at 89–90.

[55] 77 FERC ¶ 61,025.

[56] FERC Stats. & Regs. at 31,665; *mimeo* at 87–88.

[57] 76 FERC ¶ 61,009 at 61,028 (1996).

[58] FERC Stats. & Regs. at 31,668; *mimeo* at 96–98.

[59] FERC Stats. & Regs. at 31,668–79 and 31,686–87; *mimeo* at 98–129 and 148–51.

[60] Associated Gas Distributors v. FERC, 824 F.2d 981, 998 (D.C. Cir. 1987), *cert. denied*, 485 U.S. 1006 (1988) (*AGD*).

[61] Otter Tail Power Company v. FPC, 410 U.S. 366 (1974) (*Otter Tail*).

Supreme Court [in its opposition to the grant of certiorari to review the *AGD* decision] about the nature of Commission authority to order open access and judicial construction of that authority in *AGD* and *Otter Tail*;'' (5) as a matter of statutory construction, the Commission cannot rely on sections 205 and 206, which are silent as to wheeling, when sections 211 and 212 contain express wheeling provisions; (6) the four relevant cases recognized by the Commission indicate that the Commission may not directly or indirectly order a public utility to wheel or transmit energy for another entity under sections 205 and 206, notwithstanding the Commission's circumscribed ability to order wheeling under sections 211 and 212; (7) prior to the issuance of the Final Rule the Commission, with a full appreciation of the legislative history behind Part II, consistently held that it lacks the authority to order wheeling under FPA Part II; (8) the Rule fails to assign ''considerable importance'' to the Commission's ''longstanding interpretation of the statute in accordance with its literal language;'' and (9) in legislative hearings preceding enactment of EPAct, the Office of the General Counsel acknowledged the limitations on the Commission's wheeling power.

Carolina P&L also challenges the Commission's authority to order open access tariffs, arguing that: (1) *Otter Tail* specifically states: ''So far as wheeling is concerned, there is no authority granted the commission under Part II of the Federal Power Act to order it, * * *''; (2) the *Richmond* and *FPL* cases [62] prohibit the Commission from doing indirectly what it cannot do directly; (3) the *AGD* case does not support the Commission's authority to order open access through the filing of generic tariffs—in *AGD* the Commission's authority was based on voluntary actions by the affected pipelines and there are substantial differences between the NGA and the FPA; (4) the legislative history of EPAct indicates that the Commission does not have the authority to mandate open access and can only order open access if section 211 procedures are followed—citing *NYSEG* and *FPL*; and (5) section 211 limits the Commission's authority to order open access on a generic basis—where a specific statute addresses an issue, a more general statute should not be read in a manner that conflicts with the specific statute.

PA Com argues that the Commission's reliance on *AGD* ''impermissibly expands the limited holding of *AGD*'' and the Commission improperly relied on sections 205 and 206 of the FPA to require open access generically—the Commission only has case-by-case jurisdiction.

VA Com declares that the plain meaning of the FPA and cases interpreting sections 206 and 211 show that the Commission does not have the authority to order industry-wide open access.

FL Com and El Paso argue that the Commission only has limited authority to order wheeling and that the Commission has not made the required findings under section 211.[63]

Group Two Section 205 Filings

Union Electric argues that the requirement that Group 2 Public Utilities make section 205 filings is contrary to the voluntary filing scheme inherent in section 205.

Commission Conclusion

Overview

The fundamental legal question before us is the scope of the authority granted to the Commission in 1935 to remedy undue discrimination in interstate transmission services and whether that authority permits us sufficient flexibility to define undue discrimination in light of dramatically changed industry circumstances, in order to provide electricity customers the benefits of more competitively priced power. In the NOPR and Order No. 888, the Commission comprehensively examined case law and legislative history relevant to our authority to order open access transmission services as a remedy for undue discrimination.[64] We also responded at length in Order No. 888 to arguments that questioned our authority to take this step.[65]

On rehearing, as described above, only a few parties continue to question the Commission's authority. As a general matter their rehearings do not raise any arguments, cases, or legislative history not previously considered, and they do not convince us that our action in Order No. 888 is not within our authority under sections 205 and 206 of the FPA. We therefore reaffirm our determination that we have not only the legal authority, but the responsibility, to order the filing of non-discriminatory open access tariffs if we find such order necessary to remedy undue discrimination or anticompetitive effects.

There are several broad points we wish to emphasize in response to the rehearings that have been filed:

First, there is no dispute that the FPA does not *explicitly* give this Commission authority to order, *sua sponte*, open access transmission services by public utilities. However, the fact remains that the FPA does explicitly require this Commission to remedy undue discrimination by public utilities.[66] The finding of the D.C. Circuit in the AGD case, with regard to sections 4 and 5 of the NGA (which parallel sections 205 and 206 of the FPA), are equally applicable here: the Act ''fairly bristles'' with concerns regarding undue discrimination and it would turn statutory construction on its head to let the failure to grant a general power prevail over the affirmative grant of a specific one.[67]

Second, there also is no dispute that before Congress enacted the FPA in 1935, it rejected provisions that would have explicitly granted the Commission authority to order transmission to *any* person if the Commission found it ''necessary or desirable in the public interest.'' However, the fact that Congress rejected an extremely broad common carrier provision does not limit the remedies available to the Commission to enforce the undue discrimination provisions in the FPA.[68]

Third, entities on rehearing understandably have focused on statements in case law that indicate limits on the Commission's wheeling authority. They particularly focus on certain statements by the Supreme Court in *Otter Tail*. The Commission in Order No. 888 fully addressed and considered all relevant case law of which we are aware, including statements in *Otter Tail* and other court cases indicating limitations on our authority.[69] We do not dispute these statements and we

[62] Richmond Power & Light Company v. FERC, 574 F.2d 610 (D.C. Cir. 1978) (*Richmond*) and Florida Power & Light Company v. FERC, 660 F.2d 668 (5th Cir. 1981), *cert. denied sub nom.* Fort Pierce Utilities Authority v. FERC, 459 U.S. 1156 (1983) (*FPL*).

[63] We note that Indianapolis P&L also has made legal arguments regarding our authority to order wheeling under Order No. 888. However, it did so in a request for rehearing of a denial of its request for waiver of the Order No. 888 requirements, not in its request for rehearing of Order No. 888. Accordingly, we will address its arguments when we act on its request for rehearing of its waiver denial.

[64] FERC Stats. & Regs. at 31,668–73; *mimeo* at 98–112. Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,514 at 33,053–56 (1995).

[65] FERC Stats. & Regs. at 31,673–79; *mimeo* at 112–129.

[66] *See* FERC Stats. & Regs. at 31,669–70; *mimeo* at 101–03.

[67] 824 F.2d at 998.

[68] *See* FERC Stats. & Regs. at 31,676–78; *mimeo* at 120–27.

[69] *See* FERC Stats. & Regs. at 31,668–73; *mimeo* at 98–110.

recognize limitations on our authorities. However, the fact remains that none of the cases cited, including Otter Tail, involved the issue of whether this Commission can order transmission as a remedy for undue discrimination and none addressed industry-wide circumstances such as those before us in Order No. 888.

Fourth, while Congress in 1978 gave the Commission certain case-by-case authority to order transmission access by both public utilities and non-public utilities, and broadened this case-by-case authority in 1992, Congress also specifically provided in section 212(e) of the FPA that the case-by-case authorities were not to be construed as limiting or impairing any authority of the Commission under any other provision of law.[70] Indeed, the legislative history of EPAct shows that when Congress amended the section 211–212 wheeling provisions and the section 212(e) savings clause in 1992,[71] it was well aware of arguments regarding the scope of the Commission's wheeling authority as a remedy for undue discrimination under section 206. Whereas Congress in 1992 decided to add a flat prohibition on the Commission ordering direct retail wheeling under any provision of the FPA, it did not add a prohibition on the Commission ordering wholesale wheeling to remedy undue discrimination under section 206. It instead retained and modified the savings clause. The issue before us, therefore, hinges on the scope of authority given to this Commission to remedy undue discrimination, not on the scope of authority given to us in 1978 and 1992.

The Commission is significantly influenced by the decision and case law discussion by the D.C. Circuit in the AGD case. This court opinion contains the most recent and comprehensive discussion of the Commission's legal authority to remedy undue discrimination under NGA provisions that mirror those in the FPA, including the relevant case law concerning the Commission's authority to order transmission under the FPA.[72] The rehearing arguments do not, and we believe cannot, reconcile the AGD court's discussion and findings with a conclusion that the Commission cannot under any circumstances (as these parties advocate) order wheeling under sections 205 and 206 to remedy undue discrimination.

In sum, we believe that the essential question of the Commission's legal authority to impose the requirements of Order No. 888 turns on the flexibility of the Commission's remedial authority under sections 205 and 206 of the FPA to remedy undue discrimination. As was true with respect to the natural gas industry, we acknowledge that Commission precedent for many years nurtured the expectation that we would not, under our authority under the FPA, preclude utilities from using their monopoly power over the nation's transmission systems to secure their monopoly position as power suppliers. However, as described at length in Order No. 888, these policies arose in the context of practical, economic, and regulatory circumstances that gave rise to vertically integrated monopolies and little, if any, competition among power suppliers. In this kind of regime, the interests of customers were most effectively served by the kind of cost-based regulatory regime that has prevailed until very recently. The evolution of third-party generation, facilitated by PURPA and significant technological advances, dramatically altered the economics of power production. The enactment of EPAct recognized these changes and established a national policy intended to favor the development of a competitive generation market, so that the efficiencies of the new marketplace will be available to customers in the form of lower costs for electricity. Utility practices that may have been acceptable a few years ago would, if permitted to continue, smother the fledgling competitive wholesale markets and undermine the efforts of customers to seek lower-price electricity. We firmly believe that our authorities under the FPA not only permit us to adapt to changing economic realities in the electric industry, but also require us to do so, if that is necessary to eliminate undue discrimination and protect electricity customers.

Specific Arguments [73]

The Factual Circumstances Underlying AGD Do Not Mandate A Different Conclusion In This Proceeding

Both Union Electric and Carolina P&L argue that the Commission cannot rely on *AGD* in support of its actions in the electric industry, and they attempt to distinguish the legal basis on which the Commission acted in requiring open access transportation for gas pipelines. Specifically, they argue that AGD (Order No. 436) pertained to *voluntary* actions by gas pipelines and that the Commission's imposition of open access requirements was a *condition* of certificate authorizations to transport gas, whereas the Commission's action in Order No. 888 is a direct mandate.[74] We believe this is a distinction without a difference. While it is true that the Commission required open access as a condition of granting blanket authorizations for pipelines and authorizations for pipelines authorizing pipelines to transport natural gas,[75] the critical point is that in both Order No. 436 and Order No. 888 the Commission's actions hinged as a legal matter on the parallel provisions of the NGA (sections 4 and 5) and the FPA (sections 205 and 206) that prohibit undue discrimination. Whether persons are seeking to transport natural gas or wheel electric power in interstate commerce, by law they must not unduly discriminate or grant undue preference.[76]

In *AGD*, the court upheld the Commission's reliance upon sections 4 and 5 of the NGA to impose an open-access commitment on any pipeline that secured a blanket certificate to provide gas transportation under section 7 of the NGA or provided transportation under section 311 of the NGPA.[77] Order No. 436 was not a simple order that relied on the ''voluntary actions'' of affected pipelines. As the court in *AGD* understood:

> The Order envisages a complete restructuring of the natural gas industry. It may well come to rank with the three great regulatory milestones of the industry.* * *

[70] *See* FERC Stats. & Regs. at 31,686–87; *mimeo* at 148–49.

[71] The savings clause in section 212(e) originally provided that no provision of section 210 or 211 shall be treated as ''limiting, impairing, or otherwise affecting any authority of the Commission under any other provision of law.'' In 1992, the 212(e) savings clause was amended to provide that sections 210, 211 and 214 ''shall not be construed as limiting or impairing any authority of the Commission under any other provision of law.''

[72] AGD, 824 F.2d at 996–999. *See also* FERC Stats. & Regs. at 31,668–73, 31,676–78; *mimeo* at 98–110 and 120–27.

[73] We do not repeat our lengthy legal analyses in Order No. 888, but discuss only those arguments that warrant further discussion.

[74] *See* Union Electric and Carolina P&L.

[75] These authorizations are issued under section 7 of the Natural Gas Act and section 311 of the Natural Gas Policy Act.

[76] While there is a difference in the statutes in that natural gas transporters must obtain a certificate from the Commission before they can transport gas, there is no difference in the statutory standard applied to the interstate service.

[77] 824 F.2d at 997–98. The court also noted the Commission's reliance on section 16 of the NGA.

At stake is the role of interstate natural gas pipelines. Although they are obviously transporters of gas, they have until recently operated primarily as gas merchants. They buy gas from producers at the wellhead and resell it, mainly to local distribution companies (''LDCs'') but also to relatively large end users. The Commission has concluded that a prevailing pipeline practice—particularly their general refusal to transport gas for third parties where to do so would displace their own sales—has caused serious market distortions. It has found this practice ''unduly discriminatory'' within the meaning of § 5 of the NGA. Order 436 is its response.

The essence of Order No. 436 is a tendency, in the industry metaphor, to ''unbundle'' the pipelines' transportation and merchant roles. If it is effective, the pipelines will transport the gas with which their own sales compete; competition from other gas sellers (producers or traders) will give consumers the benefit of a competitive wellhead market. [78]

Indeed, since Order No. 436 issued, virtually all jurisdictional natural gas pipelines became ''open access'' transporters of natural gas.

In analyzing the Commission's authority to remedy undue discrimination, the court never made the distinctions now being put forth by Union Electric and Carolina P&L. Rather, the court specifically focused on the Commission's authority under section 5 of the NGA and upheld the Commission's authority to remedy undue discrimination in the transportation of natural gas by requiring pipelines transporting natural gas to do so on a non-discriminatory basis.[79] Similarly, the Commission in Order No. 888 found undue discrimination in the transmission of electric energy and required, pursuant to section 206 of the FPA (the FPA provision that parallels section 5 of the NGA), that if public utilities transmit electric energy in interstate commerce, they must do so on a non-discriminatory basis (*i.e.*, offer non-discriminatory open access transmission).

Moreover, while the Commission may have imposed a ''condition'' on pipelines obtaining blanket certificates or providing section 311 transportation in Order No. 436, this does not detract from the court's core finding in *AGD* that the Commission had the authority under section 5 of the NGA to remedy undue discrimination by requiring open access transportation.[80] The Commission chose in Order No. 436 to impose its open access remedy as a condition to pipelines obtaining a blanket certificate to transport natural gas, but its authority was rooted in the undue discrimination provisions of section 5. Additionally, the practical result of the conditioning was that all jurisdictional pipelines would have to provide open access transportation, a result that was clearly anticipated by the *AGD* court.[81] Thus, there is no distinction in the result intended, or the result achieved, in either industry; in both cases, the intent was to remedy undue discrimination pursuant to the statutes governing each industry, and in both cases the result was that all transporters/transmitters must agree to open access non-discriminatory services if they seek to continue owning, controlling or operating monopoly interstate transportation facilities.

Legislative History Behind the FPA and EPAct Does Not Preclude Our Action

We disagree with the arguments that the legislative history behind Part II of the FPA establishes that the Commission cannot under any circumstance order wheeling under FPA sections 205 and 206.[82] We examined the legislative history of sections 205 and 206 at length in the NOPR and Order No. 888 and concluded that it supports our authority to order open access transmission as a remedy for undue discrimination.[83] We also have examined the legislative history of the EPAct amendments to sections 211 and 212 and conclude that Congress in EPAct did not resolve the issue of our authority under sections 205 and 206 and left untouched whatever pre-existing authorities we had under these sections. The parties have raised nothing new on rehearing to persuade us that our interpretation is wrong. However, there are several arguments that we believe warrant further discussion.

Parties on rehearing argue that the existence of sections 211 and 212 limit the Commission's wheeling authority and, in effect, remove our authority under section 206 to order any transmission as a remedy for undue discrimination.[84] We disagree. In enacting EPAct, Congress did not resolve the extent of our wheeling authority outside the context of sections 211 and 212.[85] As we explained above, while Congress in 1978 gave the Commission certain case-by-case authority to order transmission access, it also specifically provided in section 212(e) of the FPA that the case-by-case authorities were not to be construed as limiting or impairing any authority of the Commission under any other provision of law. Congress retained a similar savings clause when it amended sections 211 and 212 in 1992. Moreover, the legislative history of EPAct shows that when Congress amended sections 211 and 212, it was well aware of arguments regarding the scope of the Commission's remedial authority under section 206.[86] Whereas Congress added an amendment prohibiting the Commission from ordering direct retail wheeling under *any* provision of the FPA, it chose not to add a prohibition on the Commission ordering wholesale wheeling as a remedy for undue

[78] 824 F.2d at 993–94.

[79] For example, as the *AGD* court explained with regard to its discussion of Maryland People's Counsel v. FERC, 761 F.2d 780 (D.C. Cir. 1985), ''we made it clear that blanket-certificate transportation, unconstrained by any nondiscriminatory access provision, might well require remedial action under § 5.'' 824 F.2d at 1000.

[80] We disagree with Union Electric that anything in the Commission's brief to the Supreme Court, opposing certiorari of *AGD,* contradicts our conclusion. We recognize, as the Commission explained in that brief, that there is no equivalent to section 7 of the NGA in the FPA. While this puts Order No. 888 on a somewhat different factual basis from *AGD,* it has no material effect on whether we have the authority to remedy undue discrimination by requiring non-discriminatory open access transmission.

[81] *See* 824 F.2d at 993–94 (''The Order envisages a complete restructuring of the natural gas industry. It may well come to rank with the three great regulatory milestones of the industry. * * *'').

[82] Parties have raised the legislative history of sections 205 and 206, as well as the legislative history of the EPAct amendments to sections 211 and 212.

[83] FERC Stats. & Regs. at 31,676–78; *mimeo* at 120–27. Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,514 at 33,053–56 (1995). Union Electric points to a statement in the Commission's 1987 brief to the U.S. Supreme Court, opposing certiorari of the *AGD* case; in that brief the Commission pointed out that the Supreme Court had noted, in *Otter Tail*, that the legislative histories of the FPA and NGA are ''materially different.'' As we explained in Order No. 888, we have thoroughly reexamined the legislative histories of the NGA and FPA with respect to this issue and now conclude that there is no material difference as to this issue in the legislative histories of the two statutes. Further, such a difference, whether or not it exists, was not crucial to the fundamental holdings of the *AGD* court and does not preclude that decision from applying equally in the electric industry. *See* FERC Stats. & Regs. at 31,676–78; *mimeo* at 121–26. We also note that in its brief to the Supreme Court the Commission explicitly stated that neither *Otter Tail* nor any of the other electric cases cited ''presented the question whether the Commission could order wheeling to remedy undue discrimination or anticompetitive behavior. * * *'' FERC Brief at 25 (footnote omitted).

[84] *See* discussion *supra* concerning *AGD* court's understanding that Order No. 436 was not a simple order that relied on voluntary actions of affected pipelines.

[85] Contrary to certain assertions, in Order No. 888 we viewed the statute as a whole and determined that section 211 in no way limited the broad authority Congress gave us to eradicate undue discrimination in the electric power industry.

[86] *See* note 71 and related discussion, *supra*.

discrimination under sections 205 and 206.[87]

We are not persuaded that this conclusion is wrong based on rehearing arguments that we ignored other legislative history of EPAct. Carolina P&L argues that we ignored various statements of Senator Wallop following the enactment of EPAct, which it alleges are counter to our claim of authority to order open access transmission as a remedy for undue discrimination. The utility is simply in error that we ignored these statements. We explicitly mentioned Senator Wallop's statements in Order No. 888 and gave our rationale for why section 211 does not limit our authority to remedy undue discrimination.[88] However, we believe it is important to elaborate on the context in which those statements were made and our interpretation of those statements.

The primary focus of Senator Wallop's statements is on the transmission authority given by the EPAct amendments to sections 211 and 212. These statements emphasize restrictions on our section 211 wheeling authority, including the fact that section 211 does not give the Commission authority to order transmission access on its own motion or to order open access transmission.[89] We do not quarrel with these statements because sections 211 and 212 clearly do place restrictions on our authority to order access under those provisions. The statements also discuss the differences between the House introduced amendments to sections 211 and 212 (which would have provided broader and in some instances mandatory access authority) and the amendments that finally passed (which were more limited). We also do not disagree that changes were made to the bill that originally was introduced. At issue here, however, is not whether there are restrictions on our section 211 authority, but rather whether we have authority *outside the context of section 211* to order transmission as a remedy for undue discrimination. The only statement among Senator Wallop's remarks that addresses this specific issue is one in which he says, ''*In my opinion*, neither the amendments made by this Act *nor existing law* give the FERC any authority to mandate open access transmission tariffs for electrical utilities.'' (emphasis added). We do not view one senator's opinion as in any way dispositive of the issue. As discussed *supra*, when Congress enacted the 1992 section 211 amendments it was well aware of the outstanding legal issue of the Commission's authority to order access as a remedy for undue discrimination under section 206. It chose not to clarify this issue by prohibiting the Commission from ordering access, but instead retained the savings clause in section 212(e).

The issue of our legal authority thus turns on the undue discrimination authority given to us in 1935, and the legislative history of sections 205 and 206. We discussed this at length in Order No. 888.[90] On rehearing, several entities emphasize the *Otter Tail* case and the legislative history referred to in that case. In particular, Union Electric recites Justice Stewart's discussion of the legislative history in his partial dissent in *Otter Tail*. We do not interpret that discussion to suggest that we do not have the authority to remedy undue discrimination by requiring open access transmission under any circumstance. As we explained in Order No. 888:

> In the FPA, while Congress elected not to impose common carrier status on the electric power industry, it tempered that determination by explicitly providing the Commission with the authority to eradicate undue discrimination—one of the goals of common carriage regulation. By providing this broad authority to the Commission, it assured itself that in preserving ''the voluntary action of the utilities'' it was not allowing this voluntary action to be unfettered. It would be far-reaching indeed to conclude that *Otter Tail*, which was a civil antitrust suit that raised issues entirely unrelated to our authority under section 206, is an impediment to achieving one of the primary goals of the FPA—eradicating undue discrimination in transmission in interstate commerce in the electric power industry. [91]

In response to Union Electric's arguments that Congress explicitly rejected common carrier provisions in 1935, we do not disagree with Union Electric's statement that ''the mandatory wheeling language was not dropped inadvertently.'' [92] The point that we made in Order No. 888 (quoting *AGD*) in this regard was that

> (1) ''Congress declined *itself* to impose *common carrier* status'' (emphasis added) and (2) there is no ''support for the idea that the Commission could under no circumstances whatsoever impose obligations encompassing the core of a common carriage duty.'' [93]

Nowhere did we ever suggest that the mandatory wheeling language was dropped inadvertently; we simply distinguish a general common carrier obligation imposed ''in the public interest'' from an obligation to provide transmission service deemed necessary to eliminate undue discrimination. Finally, we fully agree with Union Electric's statement that

> [a]lthough this ''first Federal effort'' occurred in 1935, the resulting FPA Sections 205 and 206 have not been modified in any relevant respect since that time. Therefore, the range of authority conveyed to the Commission in such sections remains the same today as it did then. [94]

We never suggested otherwise and our conclusion in Order No. 888 is not based on a finding to the contrary.

Case Law Does Not Prohibit Our Ordering Wheeling Under Sections 205 and 206 of the FPA

Union Electric, discussing the very cases cited by the Commission in Order No. 888, asserts that ''the Commission fails to recognize their dispositive results prohibiting it from ordering wheeling under the Sections 205 and 206 of the FPA.'' [95] We thoroughly examined all of the case law cited by Union Electric, as evidenced by our discussions in the NOPR and Order No. 888, and disagree that any of those cases prohibit the Commission from ordering wheeling under sections 205 and 206 of the FPA to remedy undue discrimination. Indeed, the *AGD* court reached the same conclusion.[96]

Union Electric further cites to a variety of FPC cases that it claims demonstrate that the Final Rule exceeds the Commission's statutory authority.[97] It appears to have proffered every negative Commission statement it could find with respect to our authority to order wheeling under Part II of the FPA.

[87] In response to Carolina P&L's argument that Congress gave the Commission a specific remedy under section 211 and the Commission should not presume that it has additional remedies in such a circumstance, we do not believe that section 211 can credibly be viewed either as a partial substitute for, or as superseding, the sections 205–206 undue discrimination remedial authority that is fundamental to the Federal Power Act. Indeed, section 211 is not written in terms of providing remedial authority to address undue discrimination but rather provides for case-by-case transmission service on request if the service is in the public interest and meets the other criteria in sections 211 and 212.

[88] FERC Stat. & Regs. at 31,686–87; *mimeo* at 148–51.

[89] Most of the statements talk in terms of ''The Conference Report provides. . . .'' and thus are referring only to the section 211 and 212 provisions. *See, e.g.*, 138 Cong. Rec. 517616 (Oct. 8, 1992).

[90] FERC Stats. & Regs. at 31,676–78; *mimeo* at 120–27.

[91] FERC Stats. & Regs. at 31,670; *mimeo* at 103.

[92] Union Electric at 26.

[93] FERC Stats. & Regs. at 31,677; *mimeo* at 122.

[94] Union Electric at 27.

[95] Union Electric at 30.

[96] The only relevant case the *AGD* court did not discuss was *NYSEG*. As we explained in Order No. 888, presumably this was because the case did not concern whether the Commission could order wheeling as a remedy for undue discrimination. FERC Stats. & Regs. at 31,672 n.217; *mimeo* at 108 n.217.

[97] Union Electric at 33–37.

As in the Commission cases cited, we recognize that our authority to order transmission service is not unbounded; if we order transmission, it must be within the scope of authority available to us under the FPA. However, the fact is that none of the cases cited as establishing limits on the Commission's authority addresses the issue before us now, *i.e.*, the Commission's authority to order transmission as a remedy for undue discrimination. Simply stated, the Commission has never before been faced with generic findings of undue discrimination in the provision of interstate electric transmission services, and the extent of its authority to remedy that undue discrimination.

The Commission's General Counsel Never Asserted, or Even Suggested, That the Commission Does Not Have the Authority to Order Wheeling as a Remedy for Undue Discrimination

Union Electric spends several pages of its rehearing request asserting that the Commission's own General Counsel has acknowledged the limitations on the Commission's authority to order wheeling. [98] In particular, it points to a statement by a Commission OGC witness that ''if Congress intends for the Commission to be able to deal with transmission on its own motion and thereby go further than simply dealing with industry proposals,'' Congress would need ''to include an affirmative statement somewhere in the Act that the Commission could require wheeling on its own motion.'' [99] This same statement was previously raised by EEI and previously addressed in Order No. 888. We do not disagree that this statement was made. However, it must be read in the context of the witness' entire testimony in which the witness stated *four* times the view that the case law supports the argument that the Commission has authority to order wheeling as a remedy for undue discrimination.[100] Indeed, contrary to Union Electric's assertion, the extensive legal analysis set forth by the Commission's witness supports the position relied upon in this proceeding.[101] Thus, viewed in the context of the witness' entire testimony, Union Electric's arguments to the contrary are unavailing. Moreover, nowhere did the witness ever suggest, as asserted by Union Electric, that FPA sections 205 and 206 could only be used ''to eliminate unduly discriminatory terms in a wheeling arrangement voluntarily filed with the Commission.'' [102]

The Commission Has the Authority to Order Public Utilities to Make Rate Filings in This Proceeding

We reject Union Electric's argument that our requirement that Group 2 Public Utilities make section 205 filings is contrary to the voluntary filing scheme inherent in section 205. It is true that the Commission ordinarily cannot require a utility to make a section 205 filing. However, in this situation the section 205 filing was required as a remedy under section 206 of the FPA to establish rates for non-discriminatory open access transmission. Acting pursuant to section 206 of the FPA, we found that undue discrimination exists in the wholesale transmission of electric power and ordered the filing of non-discriminatory open access transmission tariffs to remedy this discrimination. Section 206 further requires that upon such a finding the Commission ''shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force. * * *'' Thus, we had the authority to set the rates that would be observed and in force following the effectiveness of open access transmission and initially proposed to set rates for each public utility. However, rather than take this intrusive approach, which necessarily would have required a number of generic assumptions and resulted in less than public utility-specific rates, upon issuance of the Final Rule, we chose to permit these public utilities to make section 205 filings to propose their own rates for the services provided in the pro forma tariff.

The Commission's Prior Failure to Order Wheeling as a Remedy for Undue Discrimination Is Not Dispositive

After discussing several cases that it asserts address the Commission's authority to remedy undue discrimination, Carolina P&L declares that ''[p]erhaps the strongest evidence that the Commission lacks the power to compel wheeling under FPA section 206 is the fact that the Commission has never previously exercised this alleged power, despite numerous opportunities to do so.'' [103] However, the court in *AGD* succinctly dismissed a similar argument:

> It is finally argued that the Commission's not having imposed any requirements like those of Order No. 436 in the period from enactment in 1938 until the present demonstrates the lack of any power to do so. * * * But as our introductory review of the economic background sought to illustrate, the Commission here deals with conditions that are altogether new. Thus no inference may be drawn from prior non-use. [104]

Undue Discrimination/Anticompetitive Effects [105]

A number of utilities and state commissions argue that the Commission lacks evidence to support a finding of undue discrimination.[106]

VA Com argues that the Commission failed to make a legally supportable finding of industry-wide undue discrimination: ''FERC apparently drew a conclusion that there was undue discrimination in the NOPR without support and later accepted customers' allegations, without further inquiry, and relied on them in making its finding of industry-wide undue discrimination.'' (VA Com at 2–3).

PA Com and Carolina P&L assert that allegations of undue discrimination do not form a sufficient basis to compel a generic rulemaking. Not coming forward with specific accusations and the identity of specific accusers, PA Com asserts, is unconstitutional as a deprivation of due process.

[98] Union Electric at 37–40.

[99] Union Electric at 38–39.

[100] Hearings on H.R. 1301, H.R. 1543, and H.R. 2224 before the Subcommittee on Energy and Power of the House Committee on Energy and Commerce, 102d Cong., 1st Sess. (May 1, 2 and June 26, 1991), Statement of Cynthia A. Marlette, Associate General Counsel, Federal Energy Regulatory Commission, Report No. 102–60 at 60 (''However, as discussed below, there are strong legal arguments that the Commission's obligation to protect against undue discrimination carries with it the authority to impose transmission requirements as a remedy for undue preference or discrimination.'' ''As discussed below, although the case law in this area has been uncertain, in OGC's opinion there is a strong legal argument that the Commission can require transmission as a remedy for undue preference or undue discrimination.''); at 69–70 (''The weight of the limited case law, particularly the *AGD* opinion, supports authority to order wheeling as a remedy for undue discrimination where substantial evidence exists.''); at 106 (''I believe that we have substantial authority under the existing case law to mandate access where necessary to remedy anticompetitive effects.'').

[101] The statement quoted was preceded by a legal analysis of the Commission's authorities under then existing law, including section 206, and a statement that an examination of the Commission's *full* authorities might further open up the industry. Further, it was made in the context of case-by-case industry proposals and the Commission's inability to require case-by-case wheeling on its own motion. It did not address section 206 authority to remedy undue discrimination.

[102] Union Electric at 39. We note that Union Electric did not cite to any page or particular language to support its assertion.

[103] Carolina P&L at 35–36.

[104] 824 F.2d at 1001. In this regard, we acknowledge that our view of what constitutes undue discrimination has evolved significantly in light of the dramatic economic changes in the industry, as described briefly above and more fully in Order No. 888.

[105] FERC Stats. & Regs. at 31,682–84; *mimeo* at 136–42.

[106] *E.g.*, El Paso, Union Electric, Carolina P&L, VA Com, FL Com, PA Com.

With regard to specific allegations of undue discrimination, SoCal Edison argues that the Commission inappropriately relied upon allegations involving SoCal Edison as evidence of undue discrimination. SoCal Edison asks that the Commission declare that it is not making a factual determination as to any particular allegation especially since prior to 1994 the Commission defined discrimination differently. Dalton similarly argues that the Commission has no basis for finding that Georgia Power Company is engaged in unlawful undue discrimination as to new or roll-over transmission services in the operation of the Integrated Transmission System in Georgia (ITS) under the ITS agreement. Moreover, Dalton argues, even if it is found that GPC acted in unduly discriminatory manner, it is not practical or lawful to order open access tariff for new and roll-over services.

Finally, Carolina P&L argues that the comparability standard does not eliminate the ''requirement'' that parties must be similarly situated before discrimination is present, and that the Commission has not provided factual support for its implicit finding that public utilities and their native load customers are similarly situated to third parties. It cites *City of Vernon* v. *FERC*, 845 F.2d 1042 at 1045–46 (D.C. Cir. 1988), in support.

Commission Conclusion

As an initial matter, the Commission grants SoCal Edison's request for clarification that in Order No. 888 we did not make a factual determination as to any particular allegation of past discrimination described in the Final Rule.[107] However, we reject arguments that the Commission cannot rely in part on the array of allegations and circumstances raised by customers in individual cases over the years and brought forth in response to the NOPR. The specific allegations are illustrative. However, they present examples of the types of discriminatory incentives and behavior inherent in ownership of monopoly transmission facilities, and also present credible examples of the types of discriminatory behavior in which public utilities could engage in the future. We also reject arguments that customers and the Commission must litigate and make specific findings of discrimination against each public utility before we can take any action to preclude discriminatory behavior that will harm competition and, ultimately, electricity consumers. This is particularly true where the discriminatory behavior clearly is in the economic self-interest of a monopoly transmission owner facing the markedly increased competitive pressures that are driving today's electric utility industry. As we recognized in Order No. 888,

> [t]he inherent characteristics of monopolists make it inevitable that they will act in their own self-interest to the detriment of others by refusing transmission and/or providing inferior transmission to competitors in the bulk power markets to favor their own generation, and it is our duty to eradicate unduly discriminatory practices. As the AGD court stated: ''Agencies do not need to conduct experiments in order to rely on the prediction that an unsupported stone will fall.'' [108]

We believe that the same general discriminatory circumstances that faced us when we required open access transportation in the natural gas industry [109] are also before us today in the electric industry. First, it is uncontested that market power continues to exist in the ownership and operation of the monopoly-owned facilities that comprise the nation's interstate transmission grid. Second, utilities, as a general matter, did not in the past offer comparable transmission services to competitors or to customers. Open access services simply were not made available by utilities until the late 1980s when the Commission began to impose open access as a condition of approval of market-based rates and utility mergers in order to mitigate market power and remedy anticompetitive effects. Rather, the vast majority of utilities historically have declined to transport electric energy that would compete with their own sales or have offered access that is inferior to what they use for their own sales. Third, discrimination in transmission services, when viewed in light of utilities' own uses of their transmission systems compared to what they offer third parties, has denied and will continue to deny customers access to electricity at the lowest reasonable rates. The entities on rehearing have raised nothing to persuade us that it is in the interests of consumers to maintain the self-evident incentives for transmission owners to exercise their monopoly power over transmission to discriminate in favor of their own generation sales—incentives that will only increase in the future as competitive pressures continue to escalate.

The Commission addressed the same argument as that being made by Carolina P&L, that the Commission has not made the requisite finding that third-party transmission customers are similarly situated to public utilities and their native load customers, in 1994 in the *NEPOOL* and *AEP* cases.[110] In these cases, we recognized that the traditional focus of our undue discrimination analysis had been whether factual differences justify different rates, terms and conditions for similarly situated customers, but concluded that due to changing conditions in the electric utility industry, it was necessary to reevaluate our traditional analysis. As we stated in *NEPOOL*, the focal point of undue discrimination claims has shifted from claims of undue discrimination in rates and services which the utility offers different customers to claims of undue discrimination in rates and services which the utility offers when compared to its own use of the transmission system.[111] ''In this context, framing the analysis in terms of how a public utility treats similarly situated customers is not applicable or instructive.'' [112] The Commission concluded that it therefore must reexamine its application of the standard for undue discrimination claims under sections 205 and 206 of the FPA.

The Commission further elaborated on its re-examination of undue discrimination in *AEP*. The Commission cited its *NEPOOL* discussion and set for hearing the different uses that AEP made of its transmission system and whether there were any operational differences between any particular use that AEP made of the system and the use third parties might need, and, in particular, the degree of flexibility AEP accorded itself in using its transmission system for different purposes. The Commission subsequently set the same issue for hearing in several other cases.[113] In the NOPR, however, the Commission concluded that based on what it had learned in the ongoing cases, it would address this issue generically in this rulemaking. We announced in the NOPR our belief that

[107] In response to PA Com's and Carolina P&L's assertions that not coming forward with specific accusations and identities of specific accusers is unconstitutional and a deprivation of due process, we emphasize that the Commission has not denied due process to anyone. The Final Rule does not, nor is it intended to, make specific findings as to any particular utility or any particular allegation raised.

[108] FERC Stats. & Regs. at 331,682; mimeo at 136–37.

[109] *See AGD*, 824 F.2d at 999–1000.

[110] New England Power Pool, 67 FERC ¶ 61,402 (1994) (*NEPOOL*); American Electric Power Service Corporation, 64 FERC ¶ 61,279 (1993), *reh'g granted*, 67 FERC ¶ 61,168, *clarified*, 67 FERC ¶ 61,317 (1994) (AEP).

[111] 67 FERC ¶ 61,042 at 61,132.

[112] *Id.*

[113] Commonwealth Edison Co., 70 FERC ¶ 61,204 (1995); Wisconsin Electric Power Co., 70 FERC ¶ 61,074 (1995); and Wisconsin Public Service Corp., 70 FERC ¶ 61,075 (1995)

all utilities use their own systems in two basic ways: to provide themselves point-to-point transmission service that supports coordination sales, and to provide themselves network transmission service that supports the economic dispatch of their own generation units and purchased power resources (integrating their resources to meet their internal load). Third parties may need one or both of these basic uses in order to obtain competitively priced generation or to have the opportunity to be competitive sellers of power, and the Commission proposed that all public utilities must offer both services on a non-discriminatory open access basis.[114]

We affirmed this determination in the Final Rule. We concluded that a public utility must offer transmission services that it is reasonably capable of providing, not just those services that it is currently providing to itself or others. Because a public utility that is reasonably capable of providing transmission services may provide itself such services at any time it finds those services desirable, it is irrelevant that it may not be using or providing that service today.[115] Thus, based on the analysis in this record, the Commission has determined that undue discrimination in the provision of transmission services in today's industry does not turn on whether utilities and their native load customers are similarly situated to third parties, but instead turns on whether the utility is providing comparable service, that is, service that it is reasonably capable of providing to other users of the interstate transmission system.

In short, the Commission is not bound to a static application of its undue discrimination analysis under the FPA and, indeed, has a public interest responsibility to reexamine undue discrimination in light of changed circumstances in the industry.[116] That is what we began in *NEPOOL* and *AEP* and have completed in this rulemaking. The traditional ''similarly situated'' test, while applicable to discrimination among third-party customers, simply is not applicable when analyzing discrimination between third-party transmission customers and transmission owners. Under Carolina P&L's theory, presumably the only customers that could be shown to be similarly situated would be those who own monopoly transmission facilities and have native load (*i.e.*, captive) customers. This would preserve customer captivity, perpetuate monopoly power and profits, and deny the lowest reasonable rates to consumers. We therefore reject Carolina P&L's arguments.

Moreover, the fact that public utilities and their native load customers have been treated differently from third-party transmission customers because they are not among those traditionally considered to be ''similarly situated'' is precisely the target at which Order No. 888 takes aim. Historically, competitively-priced power was not broadly available to wholesale customers because the industry was dominated by vertically integrated IOUs[117] and, to the extent cheaper generation alternatives were available in the marketplace, transmission owners either took the cheaper power for their own uses or purchased and re-sold it at a profit.[118] Prior to EPAct, most power customers took power from the vertically integrated utilities that provided their transmission service. Transmission-only transactions played a secondary role in bulk power markets, facilitating certain economy transactions and coordination and pooling arrangements that improved utility operational efficiencies, largely as a complement to bundled bulk power transactions. Given the predominantly vertically-integrated industry and efficiencies that could be gained through encouragement of coordination and pooling transactions, the Commission was willing to accept utility practices that provided third parties with transmission services that were distinctly inferior to the utility's own uses of the transmission system.

In the future, however, unbundled transmission service will be the centerpiece of a freely traded commodity market in electricity, in which all wholesale customers can shop for power. In a market characterized by a significant increase in non-vertically integrated power suppliers and competitively priced power that is now meaningfully available, it is no longer in the interest of wholesale customers for the Commission to tolerate the types of practices that were previously accepted. We cannot allow what have become unduly discriminatory practices to erect barriers between customers and the rapidly emerging competitive electricity marketplace. Accordingly, a primary goal of Order No. 888 is to provide that in the future transmission providers and third-party transmission customers are ''similarly situated'' in the quality of transmission service available to them.

C. Comparability

1. Eligibility to Receive Non-discriminatory Open Access Transmission

In the Final Rule, the Commission modified the definition of ''eligible customer'' and, among other things, clarified that any entity engaged in wholesale purchases or sales of electric energy, not just those ''generating'' electric power, is eligible.[119] The Commission also clarified that entities that would violate section 212(h) of the FPA (prohibition on Commission-mandated wheeling directly to an ultimate consumer and sham wholesale transactions) are not eligible. Further, the Commission clarified that foreign entities that otherwise meet the eligibility criteria may obtain transmission services. The Commission also provided for service to retail customers in circumstances that do not violate FPA section 212(h). Persons that would be eligible section 211 applicants also would be eligible under the open access tariff.

a. Unbundled Retail Transmission and ''Sham Wholesale Transactions''

Rehearing Requests

Several entities assert that there is an inconsistency between tariff language and preamble language and argue that section 1.11 of the tariff should be made consistent with the preamble to ensure that, absent a state-approved program, retail wheeling is not available under the tariff, no matter which party requests service.[120] They maintain that the limitation in section 1.11 that the transmission provider only must provide retail transmission service voluntarily or under a state-approved program appears to apply only when a retail customer is the purchaser, not when the transmission purchaser is an electric utility. They suggest the

[114] FERC Stats. & Regs. ¶ 32,524 at 33,079.

[115] FERC Stats. & Regs. at 31,690; *mimeo* at 160.

[116] There is no ''requirement'' in the FPA that the Commission apply a ''similarly situated'' test. Carolina P&L's reliance on *City of Vernon* is misplaced. That case involved a claim of discrimination in the type of service offered to a wholesale customer versus that offered to retail customers, and the Commission's application of the ''similarly situated'' and ''same service'' test. Contrary to Carolina P&L's implication, the case does not hold that the Commission is bound to apply a ''similarly situated'' test in analyzing undue discrimination claims under the FPA.

[117] *I.e.*, investor-owned utilities that owned generation, transmission and distribution facilities and most of whom had captive customers.

[118] Very simply, the transmission owner was able to prevent third parties from achieving the maximum savings possible in the generation market by withholding or delaying transmission service. Alternatively, the transmission owner could purchase the power and resell it to the third party at a rate that reflected a mark-up from the first power sale.

[119] FERC Stats. & Regs. at 31,688–90; *mimeo* at 154–58.

[120] E.g., SoCal Edison, PSE&G, Carolina P&L.

following language to remedy the problem: ''however, such entity is not eligible for transmission service that would be prohibited by Sections 212(h)(1) and/or 212(h)(2) of the Federal Power Act, unless such service is provided pursuant to a state retail access program or pursuant to a voluntary offer of unbundled retail transmission service by the Transmission Provider.'' (PSE&G at 22; Carolina P&L at 8–9).

Detroit Edison argues that the Commission should modify the definition to exclude any reference to transmission service provided to retail customers so as to avoid confusion and possible forum shopping. At the least, Detroit Edison argues, the Commission should modify the language to state that transmission service is available to an ultimate consumer to the extent, and only to the extent, that the service is authorized by a lawful state retail access program or pursuant to a voluntary offer of unbundled retail transmission service by the transmission provider.

NYSEG asserts that the Commission did not apply the section 212(h) limitation to service to retail customers under the tariff. NYSEG requests that the Commission clarify that it will not require retail wheeling beyond the scope of state-mandated retail access programs or beyond the terms of a transmission provider's voluntary offer of retail wheeling service.

Oklahoma G&E asks the Commission to clarify that the term eligible customer differentiates between a customer eligible to receive transmission service and a customer whose transaction is a sham or would result in mandatory retail wheeling and would therefore be prohibited by section 212(h).

NYSEG further asserts that the right of first refusal provision would permit a retail customer receiving wheeling service to continue to take that service upon expiration of its contract, which could require the transmission provider, in violation of section 212(h), to continue retail wheeling beyond the scope of its voluntary offer of service or beyond the scope of a state-mandated retail access program.

SoCal Edison argues that the Commission cannot compel a utility to supply retail transmission service if the utility challenges the authority of the state to require retail wheeling and section 1.11 should be revised to reflect this.

IL Com declares that it ''does not recognize FERC's claim of jurisdiction over retail transmission service provided directly to a retail customer and disputes that unbundled retail wheeling directly to a retail customer is a service provided in interstate commerce.'' (IL Com at 35). Thus, ''if FERC's proposed 'deference' to states is to be given any effect, states must be allowed to determine whether the retail transmission component of the retail wheeling program will be provided pursuant to the utility's existing filed wholesale tariff or whether the retail transmission will be provided pursuant to a 'separate retail transmission tariff' that is different from the wholesale tariff.'' (IL Com at 36). IL Com concludes that it is inappropriate (and illegal if FERC is overturned on its retail transmission jurisdiction assertion) to include retail customers taking final delivery of unbundled power for their own end uses under retail wheeling programs as eligible customers.

PA Com argues that it is relevant whether a customer is receiving retail or wholesale service and redefining transmission and local distribution service does not automatically convey jurisdiction to the Commission.

CCEM asks that the Commission clarify that a retail customer eligible to seek transmission service should be able to seek transmission service not only from the transmission provider, but from any other transmission provider. CCEM also asks that the Commission add the word ''ultimate'' before the word transmission provider in section 1.11 of the tariff.

EEI asks the Commission to ''clarify that the transmission service provider should be allowed to supplement the terms and conditions of the pro forma tariff with additional provisions that specifically relate to the *totality* of the transmission service being provided, including the use of distribution facilities and any other transmission facilities not currently included in wholesale rates.'' (EEI at 24 (emphasis in original)).[121]

Union Electric argues that a literal reading of the eligibility definition could require retail wheeling by utilities in states other than those required to participate in a particular retail wheeling program.

Commission Conclusion

The Commission agrees with those entities that argue that section 1.11 of the pro forma tariff does not explicitly prohibit ''sham wholesale transactions'' that could currently be arranged under the tariff by a utility applying for service and designating the retail customer as a point of delivery. We therefore have modified section 1.11 to clarify that, with respect to service that we are prohibited from ordering by section 212(h) of the FPA (whether direct retail wheeling or ''sham'' wholesale wheeling), otherwise eligible entities may obtain such service under the tariff only if it is pursuant to a state requirement that such service be provided or pursuant to a voluntary offer of such service. We also have modified the language to clarify that eligibility for unbundled direct retail service required by a state applies only to service from transmission providers that the state orders to provide the service. The modified language states:

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.

Regarding SoCal Edison's argument, the Commission stated in the Final Rule:

Moreover, we are mindful of the fact that we are precluded under section 212(h) from ordering or conditioning an order on a requirement to provide wheeling directly to an ultimate consumer or sham wholesale wheeling. We therefore clarify that our decision to eliminate the wholesale customer eligibility requirement does not constitute a requirement that a utility provide retail transmission service. Rather, we make clear that if a utility chooses, or a state lawfully requires, unbundled retail transmission service, such service should occur under this tariff unless we specifically approve other terms.[122]

Therefore, the Commission is not compelling a utility to provide unbundled retail transmission service.[123] Rather, the Commission requires that

[121] See also CSW Operating Companies.

[122] FERC Stats. & Regs. at 31,689–90; *mimeo* at 158.

[123] We also disagree with NYSEG's assertion that the right of first refusal provision would permit a retail customer receiving wheeling service to continue to receive service after the expiration of its contract and could require the transmission provider to continue wheeling beyond the scope of its voluntary offer of service or beyond the scope of a state-mandated retail access program. Section

Continued

should such service be provided, either pursuant to state mandate or voluntarily, it must be provided pursuant to the pro forma tariff unless the Commission approves alternative terms and conditions.

However, in light of CCEM's request that we clarify that a retail customer eligible to seek transmission service under the tariff should be able to seek service not only from the transmission provider, but also from any other transmission provider, and in light of Union Electric's concerns regarding retail service eligibility, we believe certain clarifications of our jurisdiction and of the statements made in Order No. 888 are necessary. The statements cited above that were made in Order No. 888 and the eligible customer tariff definition in (ii) above refer to direct retail transmission, *i.e.,* the transmission of electric energy ''directly'' to an ultimate consumer. The Commission is prohibited by section 212(h)(1) of the FPA from ordering this type of retail transmission and that is why customers are eligible for such transmission under the tariff only if the transmission is pursuant to a state order or is provided voluntarily. However, on its face, section 212(h) does not prohibit the Commission from ordering public utilities to provide ''indirect'' unbundled retail transmission in interstate commerce, *i.e.,* the transmission necessary to transmit unbundled electric energy to a utility that ultimately will deliver the energy to a customer that is purchasing the unbundled energy at retail either pursuant to a state retail access order or pursuant to voluntary delivery by the local utility.

We clarify that we believe we have the jurisdiction under the FPA to order indirect retail transmission to an ultimate consumer and that if the Commission under sections 205, 206 or 211 of the FPA orders such transmission, entities that otherwise qualify as eligible customers under the tariff will take transmission service for such indirect retail wheeling pursuant to the pro forma tariff. We note that the Commission may order such transmission on a case-by-case basis or may determine to do so generically in the future. We expect public utilities to provide such indirect retail access under the pro forma tariff and, if they do not, we will not hesitate to order them to do so.

In response to IL Com's argument that it does not recognize this Commission's claim of jurisdiction over the rates, terms and conditions of unbundled retail transmission that is provided directly to an ultimate consumer, the Commission reaffirms its legal conclusion set forth in the Final Rule.[124] As to its claim that we should give deference to the state as to whether such service could be taken under the wholesale tariff or a separate retail tariff on file with the Commission, we reaffirm our conclusion to address this on a case-by-case basis. Since the Final Rule issued, the Commission has addressed this in several orders. In *New England Power Company,* the Commission stated: [125]

As we explained in the Open Access Rule and in the New Hampshire Interim Order, we generally expect retail transmission customers to take service under the same Commission tariff that applies to wholesale customers. While we generally will defer to state requests for a separate retail tariff to accommodate the design and special needs of a state retail access program, the Massachusetts Commission has made no such request in this case. [15]

Subsequently, in *New England Power Company,* 76 FERC ¶ 61,008 (1996), the Commission granted a limited waiver of the Open Access Rule requirements for the New Hampshire retail electric competition pilot project. Specifically, the Commission waived the requirement for individual service agreements, and the requirement for customer deposits. The Commission further announced that:

other public utilities that provide unbundled retail service under a *pro forma* tariff do not need to apply to retail customers the tariff provisions regarding individual service agreements or customer deposits, unless a state retail program so requires. [[126]]

Concerning EEI's request for clarification, the Commission stated in the Final Rule:

all tariffs need not be ''cookie-cutter'' copies of the Final Rule tariff. Thus, under our new procedure, ultimately a tariff may go beyond the minimum elements in the Final Rule pro forma tariff or may account for regional, local, or system-specific factors. The tariffs that go into effect 60 days after publication of this Rule in the Federal Register will be identical to the Final Rule pro forma tariff; however, public utilities then will be free to file under section 205 to revise the tariffs, and customers will be free to pursue changes under section 206.[[127]]

Utilities are free to include customer-specific terms and conditions or terms and conditions limited to certain customers (*e.g.,* a distribution charge) in the customer's service agreement and/or the network customer's network operating agreement.

b. Transmission Providers Taking Service Under Their Tariff

Rehearing Requests

TAPS states that section 1.11 does not seem to require a transmission provider to take service for its purchases, but the preamble does (citing *mimeo* at 57, 191, 266 and regulatory text in section 35.28(c)(2)). It argues that transmission providers should be required to treat their own usage of the transmission system to serve retail customers under the network service provisions of the tariff. TAPS argues that this result could be achieved through an ISO or by requiring transmission providers to abide by all non-price terms of Parts I and III of the tariff. TAPS also argues that the rates charged network customers must be developed on the same basis as the transmission component of retail rates. It states that the transmission provider's purchases would then be made under Part III of the tariff to the extent they are made for serving retail customers. It further asserts that the Commission's authority and obligation to consider transmission owners' service to retail load in establishing wholesale transmission rates has been long established. At the least, TAPS argues that the Commission should require that a transmission provider take its wholesale purchases under some tariff.

Similarly, Coalition for Economic Competition asks the Commission to clarify that the requirement to use the pro forma tariff for wholesale purchases and to functionally unbundle wholesale purchases and sales does not apply to purchases made solely to serve retail customers on a bundled basis. It asserts that there is conflicting language in Order No. 888 (citing *mimeo* at 191) and Order No. 889 (citing *mimeo* at 12) and the pro forma tariff. Coalition for Economic Competition asserts that the Commission does not have jurisdiction over transmission that is part of a bundled retail sale.

212(h) of the FPA would override any provision, including the right of first refusal provision, that may be included in the pro forma tariff.

[124] FERC Stats. & Regs. at 31,780 and Appendix G (31,966–81); *mimeo* at 428 and Appendix G.

[125] 75 FERC ¶ 61,356 at 62,141, *order on reh'g,* 77 FERC ¶ 61,135 (1996). In the order on rehearing, the Commission permitted a separate retail tariff to remain in effect for the duration of the retail electric pilot programs established in Massachusetts by Massachusetts Electric Company.

[15] *See* Open Access Rule, FERC Stats. & Regs. at 31,784; *New Hampshire Interim Order,* 75 FERC at 61,687 & n.3 (both noting that such a separate retail tariff must be consistent with the Commission's open access policies and comparability principles). * * *

[126] 76 FERC at 61,024.

[127] FERC Stats. & Regs. at 31,770 n. 514; *mimeo* at 399 n. 514.

Commission Conclusion

Several parties have noted on rehearing that there is conflicting language among the Final Rule, Order No. 889 and the pro forma tariff as to whether and to what extent the transmission provider must take service for ''wholesale purchases'' under its own tariff. As discussed below, we clarify that a transmission provider does not have to ''take service'' under its own tariff for the transmission of power that is purchased on behalf of bundled retail customers.

In a situation in which a transmission provider purchases power on behalf of its retail native load customers, the Commission does not have jurisdiction over the transmission of the purchased power to the bundled retail customers insofar as the transmission takes place over such transmission provider's facilities,[128] and therefore the pro forma tariff does not have to be used for such transmission. Moreover, we recognize that purchases made collectively on behalf of native load [129] cannot necessarily be identified as going to any particular customer. However, the Commission does have jurisdiction over transmission service associated with sales to any person for resale, and such transmission must be taken under the transmission provider's pro forma tariff. [130]

Order No. 888, relying on the principle of comparability, established the terms and conditions for network service provided to network customers under the pro forma tariff. Network customers may include the transmission provider itself as well as any other entity receiving Network Integration Service. If the transmission provider purchases energy from another power supplier in order to make sales to its wholesale native load customers, it must take the transmission service necessary to transmit the power from its point(s) of receipt to its point(s) of delivery under the same terms and conditions as other Network Customers.[131] As we explained in *AES Power, Inc.*, network customers are entitled to make economy energy purchases from non-designated network resources at no additional charge on a basis comparable to the economy energy purchases made by the transmission provider on behalf of its bundled retail customer.[132] This applies to the transmission provider as a network transmission customer under its own tariff as well as to other network transmission customers that make economy energy purchases on behalf of their customers. Thus, insofar as all wholesale transmission customer usage is concerned, third-party network customers are treated the same as the transmission owner.

2. Service that Must be Provided by Transmission Provider

In the Final Rule, the Commission found that a public utility must offer transmission services that it is reasonably capable of providing, not just those services that it is currently providing to itself or others. [133] The Commission explained that because a public utility that is reasonably capable of providing transmission services may provide itself such services at any time it finds those services desirable, it is irrelevant that it may not be using or providing that service today. However, the Commission explained that if a customer seeks a customized service not offered in an open access tariff, a customer may, barring successful negotiation for such service, file a section 211 application.

Rehearing Requests

Cleveland requests that the Commission make explicit that comparability will be evaluated not only by reference to a transmission provider's wholesale services, but also by comparison to the terms, conditions, and prices applicable to its retail services, whether bundled or unbundled. Cleveland asserts that this is needed so that TDUs are not at a competitive disadvantage in competing with the transmission provider for retail customers. It maintains that this is consistent with the Transmission Pricing Policy and established precedent.

Commission Conclusion

No clarification is necessary. In determining what transmission services a utility must offer for wholesale sales of electric energy in interstate commerce, the Final Rule explicitly states that ''a public utility must offer transmission services that it is reasonably capable of providing, not just those services that it is currently providing to itself or others.'' [134] Further, the Final Rule requires that network service customers receive service comparable to the service provided to the transmission provider's native load. Because the Rule applies to retail transmission that is voluntarily offered or pursuant to a state retail access program, the requirements to offer services that the utility is reasonably capable of providing and services comparable to those provided to native load would also apply to retail service in these limited retail circumstances.

3. Who Must Provide Non-discriminatory Open Access Transmission

In the Final Rule, the Commission explained that its authority under sections 205 and 206 of the FPA permits it to require only public utilities to file open access tariffs as a remedy for undue discrimination.[135] The Commission further explained that it has no authority under those sections of the FPA to require non-public utilities to file tariffs with the Commission.

The Commission also discussed three mechanisms that would help alleviate the problems associated with not being able to require non-public utilities to provide open access: (1) Broad application of section 211; (2) the reciprocity requirement set forth in the Final Rule; and (3) the formation of RTGs.

The Commission also indicated that it will not allow public utilities that jointly own interstate transmission facilities with non-jurisdictional entities to escape the requirements of open access. Thus, the Commission required each public utility that owns interstate transmission facilities jointly with a non-jurisdictional entity to offer service over its share of the joint facilities, even if the joint ownership contract prohibits service to third parties. The Commission required the public utilities, in a section 206 compliance filing, to file with the Commission, by December 31, 1996, a proposed revision (mutually agreeable

[128] To the extent the transmission takes place on the interstate facilities of other public utilities, we would have jurisdiction over such transmission.

[129] Native load means ''[t]he 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.'' Section 1.19 of the pro forma tariff.

[130] All transmission in interstate commerce by a public utility in conjunction with a sale for resale of electric energy is jurisdictional and must be taken under a FERC-jurisdictional tariff. The same is true for all unbundled transmission in interstate commerce to wholesale customers, as well as to unbundled retail customers.

[131] Under the Order No. 888 pro forma tariff, third-party wholesale customers have the ability to obtain the identical service the transmission provider provides itself when it engages in a sale of electric energy for resale. This may include network or point-to-point service.

[132] 69 FERC ¶ 61,145 at 62,300 (1994) (proposed order), 74 FERC ¶ 61,220 (1996) (final order).

[133] FERC Stats. & Regs. at 31,690; *mimeo* at 160.

[134] FERC Stats. & Regs. at 31,690; *mimeo* at 160.

[135] FERC Stats. & Regs. at 31,691–92; *mimeo* at 162–65.

or unilateral) to their contracts with non-jurisdictional owners.

Rehearing Requests

Jointly-Owned Facilities

Union Electric argues that the Final Rule improperly requires a public utility to unilaterally file a modification to agreements that a non-jurisdictional entity opposes, which amounts to a litigation coercion provision. Union Electric notes that it has been told by Associated Electric Cooperative, Inc. that it will oppose any modifications to Union Electric's agreements. Union Electric further states that these facilities are not commonly owned, but rather each party wholly owns its segment of the facilities.

Dalton asserts that Georgia Power Company cannot comply with the requirement to offer service over its share of joint facilities because the ITS is not owned by members as tenants in common, but instead each member owns specific segments of the transmission grid. Dalton further argues that it is unjust and unreasonable to require Georgia Power Company to give access to the ITS to new and roll-over transmission customers under the Order No. 888 tariff that are unwilling to accept an investment responsibility and an obligation to make balancing payments.

Associated EC argues that the Commission may modify non-jurisdictional contracts only under section 211 of the FPA; the Commission cannot simply modify the contract with respect to the public utility.

NE Public Power District states that it is party to an agreement with a public utility involving jointly constructed transmission facilities that prohibits use of the transmission capacity by a non-party. It asserts that ''[t]he District's contractual rights under its contract constitute valuable property, and the summary annulment of those rights constitutes a violation of Due Process.'' (NE Public Power District at 18–20). Moreover, it argues that blanket invalidation of the terms and conditions of the contracts is contrary to the *Sierra-Mobile* doctrine.

Commission Conclusion

We reject those arguments that maintain that the Commission cannot properly require a public utility to file unilaterally a modification to agreements concerning joint transmission facilities that a non-jurisdictional entity opposes. It is without question that the Commission has the exclusive authority to regulate public utilities engaged in the sale for resale and/or transmission of electric energy in interstate commerce to assure that rates, terms and conditions are just and reasonable and not unduly discriminatory. The fact that a public utility may jointly own, with a non-jurisdictional entity, transmission facilities through which it engages in sales for resale and/or transmission of electric energy in interstate commerce does not alter the Commission's authority to regulate that public utility.[136] If the Commission finds that a matter needs to be remedied, it may issue an order directed at the public utility. The fact that such an order may affect a non-jurisdictional joint owner does not undermine the validity of the Commission's order.[137] Otherwise, a public utility could simply enter into joint agreements with non-jurisdictional utilities to the frustration of the Commission's mandate to protect consumers from undue discrimination.[138]

Nor does the exercise of the Commission's powers under the FPA to remedy undue discrimination by public utilities constitute a violation of due process vis-a-vis the non-jurisdictional entity. When the contract was entered into and filed with the Commission it was with the explicit knowledge that the Commission could regulate the rates, terms and conditions of the contract with respect to the jurisdictional services provided thereunder by the public utility. If and when a public utility unilaterally files either to amend or terminate the agreement, the non-jurisdictional party is free to raise any arguments it wishes to support its position that no changes are necessary to ensure that the contract is just and reasonable and not unduly discriminatory or preferential.

4. Reservation of Transmission Capacity by Transmission Customers

In the Final Rule, the Commission concluded that firm transmission customers, including network customers, should not lose their rights to firm capacity simply because they do not use that capacity for certain periods of time.[139]

Rehearing Requests

No rehearing requests addressed this matter.

5. Reservation of Transmission Capacity for Future Use by Utility

In the Final Rule, the Commission concluded that public utilities may reserve existing transmission capacity needed for native load growth and network transmission customer load growth reasonably forecasted within the utility's current planning horizon.[140] However, the Commission determined that any such capacity that a public utility reserves for future growth, but is not currently needed, must be posted on the OASIS and made available to others through the capacity reassignment requirements, until such time as it is actually needed and used.

Rehearing Requests

CCEM argues that it is discriminatory to allow public utilities and network transmission customers to reserve existing transmission capacity for their native load growth because it (1) limits the determination of ATC, (2) is likely to increase the cost of transmission for other customers, and (3) is inconsistent with a capacity reservation-based system. CCEM argues, however, that if the reservation feature is retained, franchise utilities that reserve capacity must pay the full reservation charges, with no cost shifting to other customers. CCEM further recommends that all reservation payments should be credited directly to firm transmission services and the planning horizon should be limited to a reasonable time into the future.

American Forest & Paper argues that to achieve comparability, utilities must not be permitted to withhold capacity from the market for the benefit of native load. American Forest & Paper further argues that the Commission must establish mechanisms for evaluating the reasonableness of the utilities' requirements and projections, otherwise they have an incentive to over-forecast and to extend their planning horizons. American Forest & Paper suggests that requiring utilities to establish separate entities to purchase transmission on behalf of their native load would help solve this problem.

VA Com requests that the Commission clarify what will happen if a utility's forecast of load growth is too low. It argues that native load should not have to bear the burden of any forecast errors and that utilities should be required to reserve sufficient capacity to serve the current and projected needs

[136] See Policy Statement Regarding Regional Transmission Groups, 64 FERC ¶ 61,139 at 61,993 (1993); Midwest Power Systems, Inc., 69 FERC ¶ 61,025 at 61,104–05 (1994). Nor does the form of ownership of the joint facilities have any bearing on the Commission's jurisdiction over public utilities.

[137] Though the non-jurisdictional entity would not become subject to Commission regulation.

[138] Cf. H.K. Porter Co., Inc. v. Central Vermont Railway, Inc., 366 U.S. 272, 273–75 (1961).

[139] FERC Stats. & Regs. at 31,693; *mimeo* at 168–70.

[140] FERC Stats. & Regs. at 31,694; *mimeo* at 172.

of native load customers. VA Com would also have the definition of native load in section 1.19 of the tariff expanded to include existing distribution cooperatives and others who currently provide service to end users. With respect to reservation priority, VA Com states that the Commission should establish the following reservation priority: native load customers, firm contract customers, and non-firm customers. Finally, VA Com asserts that the calculation of ATC must not include any capacity that may be needed by native load customers.

Commission Conclusion

We will deny the requests of CCEM and American Forest and Paper. We continue to believe that public utilities should be allowed to reserve existing transmission capacity needed for native load growth and network customer load growth reasonably forecasted within the utility's current planning horizon.

We note that network service is founded on the notion that the transmission provider has a duty to plan and construct the transmission system to meet the present and future needs of its native load and, by comparability, its third-party network customers. In return, the native load and third-party network customers must pay all of the system's fixed costs that are not covered by the proceeds of point-to-point service. This means that native load and third-party network customers bear ultimate responsibility for the costs of both the capacity that they use and any capacity that is not reserved by point-to-point customers. In this regard, native load and third-party network customers face a payment risk that point-to-point customers generally do not face. For these reasons, we do not believe that it is appropriate to require native load and network customers to assume any additional cost responsibility for the capacity that is reserved for their future use.

In response to CCEM's concerns, we recognize that offering load-based network service and reservation-based point-to-point service in one tariff may have disadvantages in that it may result in less than optimal use of the system if a utility overestimates its load. However, by requiring that available capacity reserved for native load be posted on OASIS and be available to others except when actually needed to serve native load, we believe Order No. 888 substantially relieves the incentive to over-reserve for native load and goes a long way toward assuring full and efficient use of the system.

With regard to the concern raised by VA Com, the transmission provider has an ongoing duty to plan and construct its system in a prudent manner in order to meet all of its firm service obligations. We also reiterate that

> public utilities may reserve existing transmission capacity needed for native load growth and network transmission customer load growth reasonably forecasted within the utility's current planning horizon.[141]

There is a risk of under-or over-projecting the transmission needs of native load and network customers, and the native load and network customers' cost responsibilities reflect this additional risk. In response to VA Com's request, we note that nothing in our regulations prohibits a state commission from overseeing a utility's retail native load growth projections. Finally, concerns regarding the accuracy of load growth projections for native load and network customers may be raised when a transmission service agreement is filed with the Commission or in a separate section 206 proceeding.

6. Capacity Reassignment

In the Final Rule, the Commission concluded that a public utility's tariff must explicitly permit the voluntary reassignment of all or part of a holder's firm transmission capacity rights to any eligible customer.[142]

(1) Reassignable Transmission Services

The Commission concluded that point-to-point transmission service should be reassignable, but that network transmission service is not reassignable.[143]

(2) Terms and Conditions of Reassignments

a. General

In effecting a reassignment, the Commission found that the assignor may deal directly with an assignee without involvement of the transmission provider.[144] Alternatively, the Commission explained that the assignor may request the transmission provider to effect a reassignment on its behalf, in which case the transmission provider must post the available capacity on its OASIS and assure that any revenues associated with the reassignment are credited to the assignor. The Commission further found that, among other things, any assignment must be posted on the transmission provider's OASIS within a reasonable time after its effective date.

b. Contractual Obligations

The Commission concluded that while assignors and assignees may contract directly with each other, the assignor will remain obligated to the transmission provider and the assignee will be liable solely to the assignor.[145] The Commission, however, did permit mutually agreeable alternatives to this approach.

c. Price Cap

The Commission concluded that the rate for any capacity reassignment must be capped by 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).[146]

Rehearing Requests

Scheduling Transmission Service by Assignees

CCEM requests that the Commission clarify that an assignee of transmission capacity, or its agent, is permitted to schedule transmission service directly with the transmission provider.

Network Transmission Service

American Forest & Paper declares that the Commission erred in finding that network service is not reassignable. American Forest & Paper argues that there is no technical reason for the Commission's position. According to American Forest & Paper, the Commission merely perpetuates the myth that in point-to-point transmission the contract actually determines the path of the flow of electrons. In fact, American Forest & Paper argues, the only issue is arriving at a nondiscriminatory and equitable price.

VT DPS argues that there is no reason network capacity rights cannot be defined during the period of a reassignment as VT DPS suggested in its comments:

> Section 2.6 of the NorAm NIS Rate Schedule (Appendix B to the Initial NOPR comments of VDPS) is a provision which allows the reassignment of network service. Reassignment under the NorAm tariff would work this way: During the period of the assignment, both the original and replacement customers' network service entitlements are defined as specified contract quantities, the sum of which is equal to the original customer's highest coincident peak load during the 12 months preceding the

[141] FERC Stats. & Regs. at 31,694; *mimeo* at 172.

[142] FERC Stats. & Regs. at 31,696; *mimeo* at 178–179.

[143] FERC Stats. & Regs. at 31,696; *mimeo* at 179.

[144] FERC Stats. & Regs. at 31,696–97; *mimeo* at 179–80.

[145] FERC Stats. & Regs. at 31,697; *mimeo* at 180–81.

[146] FERC Stats. & Regs. at 31,697; *mimeo* at 181.

assignment. During the period of the assignment, that contract quantity, not the actual use of the system by the original and replacement shipper, will be used to determine the two customers' load ratio share responsibility. The original and replacement customers are free to divide responsibility for interim contract demand between them as they see fit.[147]

PA Coops argue that the Commission failed to explain why network customers have no capacity rights and points to a statement in Order No. 888 that network customers ''should not lose their rights to firm capacity'' as being inconsistent with the Commission's conclusion with respect to the reassignment of network service.

AMP-Ohio asserts that absent an ongoing pass-through to network customers of the revenue credits associated with sales of point-to-point service, the Commission should permit the reassignment of unused transmission capacity by network customers.

TDU Systems argue that the Commission should permit the assignment of a network customer's right to network transmission service for certain specific purposes. In particular, TDU Systems state that the Commission should permit assignment to allow a customer to coordinate, jointly operate, or pool its system with the systems of other local and regional network customers. TDU Systems argue that this provides an opportunity to maximize efficiencies without presenting the complication that the Commission has perceived with respect to the reassignment of point-to-point transmission capacity.

Price Cap

EEI asserts that the Commission's price cap creates several problems: (1) non-comparable treatment because transmission providers must credit revenues, but resellers can keep the revenues; (2) allowing sale at a price higher than paid could encourage speculation and hoarding; and (3) the transmitting utility's maximum stated rate should not include the utility's opportunity costs.

CCEM argues that transmission customers that are not transmission providers or affiliates of transmission providers should be freed from the price cap. CCEM claims that in a secondary market at market-based prices, opportunity costs can be communicated and lost opportunity costs averted.

NRECA believes that the price cap provision that permits an assignor to assign capacity at its own opportunity costs (capped at the cost of expansion) may provide firm point-to-point customers a strong economic incentive to buy up substantial firm capacity for speculative purposes and argues that this provision should be eliminated. NRECA also argues that this provision presents difficult rate substantiation questions when the assignor is not a public utility. Further, NRECA and SoCal Edison note that section 23.1 of the tariff does not include the cap at the cost of expansion.

Calculation of Assignor's Opportunity Costs

SoCal Edison asserts that the Commission must indicate how an assignor should calculate its own opportunity costs with respect to determining the price cap and should indicate that an assignor must abide by the same standard for recovering opportunity costs as the transmission provider. Carolina P&L also asserts that assignors must be held to the same standard as transmission providers when calculating opportunity costs. Carolina P&L further explains that if the opportunity costs are based on the cost of foregone transactions, the assignor should be required to post the price on OASIS.

Carolina P&L also asks that the Commission clarify how an assignor is to calculate its own opportunity costs. In particular, Carolina P&L asks if an assignor is limited to recovering the opportunity costs to which it is subject under the transmission provider's tariff or can the assignor forfeit the transaction underlying the transmission service and call the resulting difference an opportunity cost?

Resellers Into the Secondary Market

CCEM argues that the Commission should free resellers, ''who but-for the resell would not be public utilities,'' from regulation as public utilities or should minimize the regulatory burden on them.[148] It further asserts that resellers that are not transmission providers should be treated like unaffiliated power marketers and granted waivers from public utility regulations.

Participation in the Secondary Market

CCEM argues that those customers that are permitted to continue to take service under existing agreements ''should be excluded from participating in the secondary market until such time as they agree to comply with the pro forma tariff.'' (CCEM (889 rehearing request) at 7).

Commission Conclusion

Scheduling Transmission Service by Assignee

The pro forma tariff does not prohibit the assignee of transmission capacity from scheduling transmission service with the transmission provider. In fact, the tariff provides that ''the Assignee will be subject to all terms and conditions of this Tariff'' (tariff section 23.1), which would include the scheduling provision of tariff sections 13.8 and 14.6.

Network Transmission Service

We reaffirm our conclusion that network transmission service is not reassignable in the secondary market.[149] Parties have raised no new arguments that would persuade us otherwise. PA Coops are nevertheless correct in noting that network customers do have rights to firm capacity. However, a network customer's rights (as well as the transmission provider's planning responsibilities) are defined only in terms of the capacity needed to integrate the network customer's designated resources and its designated loads. These are usage- or load-based rights that are not fixed; they vary as the customer's load varies. Thus, the network customer's capacity rights are not well enough defined to be generally reassignable in the secondary market.[150]

VT DPS proposes a formula for defining a network customer's entitlement that would be operative during the period of an assignment. However, the proposed definition is simply an artifice derived from the load ratio share calculation. The formula does not result in a reassignable capacity right.

AMP–Ohio's suggestion regarding the proper treatment of the revenue credits associated with point-to-point service raises a rate issue that should be addressed in a ratemaking proceeding. However, we note that the proper treatment of such credits does not turn on the assignability of network service.

Finally, TDU Systems' recommendation that network service be reassignable only for pooling and coordination purposes is without merit. If customers wish to avail themselves of network service in order to realize

[147] VT DPS at 47–48; *see also* Valero at 29–31.

[148] CCEM makes this argument in its rehearing request of Order No. 889.

[149] While portions of network transmission service are not reassignable, we would permit the reassignment of a particular network transmission service in its entirety.

[150] We note that the question of how network service may be converted into a service that is reassignable is at issue in the Capacity Reservation Tariff NOPR proceeding in Docket No. RM96–11–000.

benefits associated with joint or coordinated operations with other systems, they can jointly request network service from the transmission provider. To allow customers to opt into and out of network service arrangements under the guise of capacity reassignment would be an abuse of the terms and conditions of the service, which, among other things, requires the transmission provider to plan for the long-term needs of network customers.

Price Cap

We will also reaffirm our conclusions regarding the price cap applicable to capacity reassignment. We continue to believe that customers must be given limited pricing flexibility in order to achieve the full efficiency and risk management benefits of capacity reassignment.

Contrary to the assertions of EEI and NRECA, we are not persuaded that allowing the customer to reassign capacity at a rate higher than it paid, as a result of charging its own opportunity costs, will lead to speculation and hoarding. As a condition of the open access tariff, the Commission will require customers reassigning transmission capacity to fully develop their method for calculating opportunity costs and provide all information necessary to their customers in order to verify such costs. Further, we reiterate that the potential for hoarding can be mitigated by (1) allowing the transmission provider to sell any reserved but unscheduled point-to-point transmission capacity on a non-firm basis, and (2) having a price cap, which allows the reseller to charge no more than a cost-based rate, including its own opportunity cost for reassigned capacity. Therefore, the reseller will find that reassigning transmission capacity to others with higher valued uses will be in its economic self interest. In addition, any hoarding of capacity that has anticompetitive effects can be addressed under section 206.

We deny CCEM's request to remove the price cap for transmission customers that are not transmission providers or affiliates of transmission providers. As we stated in the Final Rule, we are unable to conclude that competition in the market for reassigned transmission capacity is sufficient to prevent assignors from exerting market power. Thus, we believe the opportunity cost cap should be retained.[151]

Finally, in response to EEI's request, we clarify that ''the transmission provider's maximum stated firm transmission rate in effect at the time of the reassignment'' does not include the transmission provider's opportunity costs.[152] Also, as suggested by NRECA and others, section 23.1 of the pro forma tariff will be revised to indicate that the assignor's opportunity costs are capped at the transmission provider's cost of expansion.

Calculation of Assignor's Opportunity Costs

In response to the requests of SoCal Edison and Carolina P&L, we clarify that the assignor's opportunity costs should be measured in a manner that is analogous to that used to measure the transmission provider's opportunity costs. That is, an assignor's opportunity costs include: (1) increased costs associated with changes in power purchases or in the dispatch of generating units necessary to accommodate a reassignment, and (2) decreased revenues that arise from the assignor having to reduce sales of power in order to effect the reassignment.[153]

Regarding the calculation of opportunity costs, we intend to hold assignors to the same general standard as transmission providers. Thus, consistent with our treatment of transmission providers, we will not require assignors to post their opportunity costs on the OASIS or to make the costs routinely available to the public. We will, however, require assignors to describe to their assignees their derivation of opportunity costs in sufficient detail to satisfy the assignees that the price charged does not exceed the higher of (i) the original rate paid by the reseller, (ii) the transmission provider's maximum rate on file at the time of the assignment, or (iii) the reseller's opportunity cost, as set forth in section 23.1 of the tariff.

Resellers Into the Secondary Market

The issues raised by CCEM with respect to the regulation of resellers into the secondary market are fact specific and, accordingly, we will address such issues on a case-by-case basis.

Participation in the Secondary Market

We reject CCEM's argument that those customers that are permitted by Order No. 888 to continue to take service under existing agreements should be denied access to the secondary market until they agree to comply with the pro forma tariff. CCEM's approach would undermine our determination not to generically abrogate existing agreements, and would slow the growth of the secondary market by limiting the number of eligible participants.

7. Information Provided to Transmission Customers

In the Final Rule, the Commission concluded that all necessary transmission information, as detailed in the OASIS Final Rule, must be posted on an OASIS.[154]

Rehearing Requests

No requests for rehearing addressed this matter.

8. Consequences of Functional Unbundling

a. Distribution Function

In the Final Rule, the Commission concluded that the additional step of functionally unbundling the distribution function from the transmission function is not necessary at this time to ensure non-discriminatory open access transmission.[155]

Rehearing Requests

No requests for rehearing addressed this matter.

b. Retail Transmission Service

In the Final Rule, the Commission explained that although the unbundling of retail transmission and generation, as well as wholesale transmission and generation, would be helpful in achieving comparability, it did not believe it was necessary.[156] The Commission further explained that the matter raises numerous difficult jurisdictional issues that are more appropriately considered when the Commission reviews unbundled retail transmission tariffs that may come before the Commission in the context of a state retail wheeling program.

Rehearing Requests

CCEM argues that all transmission must be unbundled, including currently bundled retail transmission service, because failure to do so is inconsistent with the Commission's assertion of jurisdiction over the rates, terms, and conditions of unbundled interstate transmission to retail customers and

[151] We note that if the assignor is a public utility it will in any event have to file a rate schedule for the re-sale (reassignment) of unbundled transmission.

[152] We also reject as unsupported EEI's comparability argument that transmission providers must treat any transmission service revenues as a revenue credit, but the reseller may keep any transmission resale revenues.

[153] In response to Carolina P&L's request, we clarify that the assignor is *not* limited to recovering the opportunity costs to which it is subject under the transmission provider's tariff, *i.e.*, the transmission provider's opportunity costs.

[154] FERC Stats. & Regs. at 31,698; mimeo at 183–84.

[155] FERC Stats. & Regs. at 31,699; *mimeo* at 186.

[156] FERC Stats. & Regs. at 31,699–700; *mimeo* at 188.

authority to address retail stranded costs through its jurisdiction over such costs. CCEM notes that the Commission found it necessary in Order No. 636 to unbundle the pipeline's direct retail sales to achieve comparability (CCEM cites *FPC* v. *Conway Corp.,* 426 U.S. 271, 273 (1976) and *Mississippi River Transmission Corp.* v. *FERC,* 969 F.2d 1215 (D.C. Cir. 1992) for the proposition that the Commission has jurisdiction over all interstate transmission).

NY Municipal Utilities and American Forest & Paper also argue that the Commission erred in not requiring the unbundling of the transmission component of *retail* sales. American Forest & Paper believes that such unbundling will facilitate competition by making the generation price transparent to all participants.

Commission Conclusion

We disagree with those entities that argue that the Commission erred in not requiring the unbundling of all transmission service, including the unbundling of transmission from retail service. As we explained in the Final Rule:

> 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. Under the FPA, the Commission's jurisdiction over sales of electric energy extends only to wholesale sales. However, when a retail transaction is broken into two products that are sold separately (perhaps by two different suppliers: an electric energy supplier and a transmission supplier), we believe the jurisdictional lines change. In this situation, the state clearly retains jurisdiction over the sale of the power. However, the unbundled transmission service involves *only* the provision of ''transmission in interstate commerce'' which, under the FPA, is exclusively within the jurisdiction of the Commission. Therefore, when a bundled retail sale is unbundled and becomes separate transmission and power sales transactions, the resulting transmission transaction falls within the Federal sphere of regulation.[157]

Nor is our decision not to unbundle transmission from retail generation service inconsistent with our assertion of jurisdiction over unbundled interstate transmission to retail customers. As we explained in the Final Rule and described further above, we have exclusive jurisdiction under the FPA over ''transmission in interstate commerce'' by public utilities, which includes the unbundled interstate transmission component of a previously bundled retail transaction.[158] Our assertion of jurisdiction in such a situation arises only if the retail transmission in interstate commerce by a public utility occurs voluntarily or as a result of a state retail program.

c. Transmission Provider

1. Taking Service Under the Tariff

In the Final Rule, the Commission concluded that public utilities must take all transmission services for wholesale sales under new requirements contracts and new coordination contracts under the same tariff used by others (eligible customers).[159] For sales and purchases under existing bilateral economy energy coordination agreements, the Commission gave an extension until December 31, 1996 for public utilities to take transmission service under the same tariff used by others. The Commission also gave an extension of time to December 31, 1996 for certain existing power pooling and other multilateral coordination agreements to comply with this requirement.[160]

Rehearing Requests

This issue is discussed above in Section IV.C.1.b.

2. Accounting Treatment

In the Final Rule, the Commission directed utilities to account for all uses of the transmission system and to demonstrate that all customers (including the transmission provider's native load) bear the cost responsibility associated with their respective uses.[161]

Rehearing Requests

No requests for rehearing addressed this matter.

D. Ancillary Services

In the Final Rule, the Commission concluded that the following six ancillary services must be included in an open access transmission tariff: (1) Scheduling, System Control and Dispatch Service; (2) Reactive Supply and Voltage Control from Generation Sources Service; (3) Regulation and Frequency Response Service; (4) Energy Imbalance Service; (5) Operating Reserve—Spinning Reserve Service; and (6) Operating Reserve—Supplemental Reserve Service.[162] The Commission adopted NERC's recommendations for ancillary service definitions and descriptions with modifications.[163]

The Commission determined that the transmission provider must provide and the transmission customer must purchase from the transmission provider the first two services, subject to conditions set out in the Rule. The transmission provider must offer the remaining four services to the transmission customer serving load in the transmission provider's control area. The transmission customer that is serving load in the transmission provider's control area must acquire these four services from the transmission provider or a third party, or self provide.

1. Specific Ancillary Services

a. Scheduling, System Control and Dispatch Service

In the Final Rule, the Commission concluded that Scheduling, System Control and Dispatch Service is necessary to the provision of basic transmission service within every control area.[164] The Commission further stated that this service can be provided only by the operator of the control area in which the transmission facilities used are located.

Rehearing Requests

Wisconsin Municipals asks that the Commission eliminate Schedule 1 (Scheduling, System Control and Dispatch Service) as an ancillary service and require transmission providers to include these costs in the transmission revenue requirement so the transmission provider cannot recover these costs twice. Alternatively, Wisconsin Municipals asks that, if customers do their own scheduling through an electronic data link, the charge for scheduling and dispatch be waived.

Commission Conclusion

We disagree with Wisconsin Municipals that we should eliminate this ancillary service and include its

[157] FERC Stats. & Regs. at 31,781; *mimeo* at 430–31 (emphasis in original). As discussed in Section IV.I., *infra,* we believe this jurisdictional determination is supported by the statute and the case law, including the D.C. Circuit's recent decision in United Distribution Companies v. FERC, 88 F.3d 1105 (1996).

[158] FERC Stats. & Regs. at 31,781; *mimeo* at 431.

[159] FERC Stats. & Regs. at 31,700–01; *mimeo* at 191. *See also* discussion *infra* at Section IV.G. Section 1.11 (and Section 13.3).

[160] By notice issued September 27, 1996 in Docket Nos. RM95–8–000 and RM94–7–001, the Commission revised the compliance dates. It required joint pool-wide section 206 compliance tariffs to be filed no later than December 31, 1996, and pool members to begin taking service under the tariffs 60 days after the section 206 filing. It also gave members of public utility holding companies an extension of time to take service under their system-wide tariff until no later than March 1, 1997.

[161] FERC Stats. & Regs. at 31,703; *mimeo* at 198.

[162] FERC Stats. & Regs. at 31,703–04; *mimeo* at 199.

[163] In comments on the proposed rule, NERC identified additional interconnected operations services that it indicated may be necessary for reliability. As discussed in the Final Rule, we do not require the transmission provider to be the default provider of these other services.

[164] FERC Stats. & Regs. at 31,716; *mimeo* at 238.

costs with the transmission revenue requirement. Scheduling requires action by both the customer who provides information about a transaction and the control area that evaluates and accepts (schedules) the transaction. If a transmission provider allows a transmission customer to supply its schedules through an electronic data link, it is merely offering an alternate method of providing the transaction information required. The control area must still decide whether it can schedule a transaction. Further, scheduling a transaction is only one aspect of Scheduling, System Control and Dispatch Service. A control area must also dispatch generating resources to maintain generation/load balance and maintain security during the transaction. Only the control area operator can perform these functions. A transmission provider must unbundle the cost of these functions, including scheduling, from its base transmission rate. This requirement to unbundle ancillary services costs from the base transmission rate ensures that double recovery of scheduling costs will not occur.

b. Reactive Supply and Voltage Control From Generation Sources Service

In the Final Rule, the Commission concluded that Reactive Supply and Voltage Control from Generation Sources Service is necessary to the provision of basic transmission service within every control area.[165] Although a customer is required to take this ancillary service from the transmission provider or control area operator, the Commission stated that a customer may reduce the charge for this service to the extent it can reduce its requirement for reactive power supply.

Rehearing Requests

NRECA and TDU Systems ask that Schedule 2 of the tariff, Reactive Supply and Voltage Control from Generation Sources Service, be modified to reflect that generation facilities outside a control area can provide reactive power. They argue that parties other than the transmission provider and the transmission customer are able to supply reactive power. Similarly, Santa Clara and Redding ask the Commission to revise Schedule 2 to require the transmission provider to offer this service, but to allow the transmission customer to arrange for this service through a purchase from the transmission provider, self-provision, or purchases from third parties.[166] Blue Ridge also argues that the Commission should permit self-supply or other local supply when it is feasible and economic to do so.

APPA, Santa Clara, Redding and Cajun point out an inconsistency between Schedule 2 and the preamble. They assert that Schedule 2 of the tariff should be revised to reflect the preamble language that allows a transmission customer to supply at least a portion of its reactive power service. California DWR says that it is capable of providing Reactive Supply and Voltage Control from Generation Sources Service and that mandating that it purchase this ancillary service makes no sense. California DWR asks the Commission to clarify that it is not required to purchase this ancillary service.

TAPS asks the Commission to make clear that (1) customer-owned generation facilities that are available to supply reactive power to the transmission provider's transmission system receive a credit, (2) the extent of customer-supplied reactive power may be sufficient to eliminate the need for a separate reactive power charge paid to the transmission provider, and (3) customer-owned generation outside the control area may be eligible for a credit if it is located nearby where it can provide reactive support for the transmission provider's transmission system.[167] TAPS further asserts that reactive supply service should be viewed not on a transaction basis but on a gridwide or regionwide basis. Under this approach, according to TAPS, payments would be based on whether the user supplies more than it uses or uses more than it supplies.

Commission Conclusion

Control area operators use sources of reactive support to control voltage and maintain a stable power supply system. Because of the limited ability to transmit reactive power, these facilities must be available at or near the point of need. Therefore, reactive power support, and hence the facilities able to provide (or absorb) reactive power, must be distributed throughout the transmission system for the reliable operation of the power system. Over- or under-supply of reactive power at other points in the network do not contribute to a stable system and could harm the reliability of the system.

Although we agree with NRECA and TDU Systems that generation resources just outside the boundaries of a control area may provide some reactive support within the control area, the control area operator must be able to control the dispatch of reactive power from these generating resources. Accordingly, we will modify Schedule 2 to refer to generating facilities that are under the control of the control area operator instead of in the control area. The transmission customer's service agreement should specify the generating resources made available by the transmission customer that provide reactive support.

As noted in the Final Rule, a transmission customer can reduce (but not eliminate completely) the reactive supply and voltage control needs and costs that its transaction imposes on the transmission provider's system. For example, a customer who controls generating units equipped with automatic voltage control equipment may be able to use those units to help control the voltage locally and reduce the reactive power requirement of the transaction.[168] However, if these units are not always available or are not subject to the direction of the control area operator, their occasional use may not reduce the investment required by the control area operator in reactive power facilities. It merely reduces temporarily the cost of operating these facilities. Consistent with this understanding, we will modify Schedule 2 of the tariff to allow a transmission customer to supply at least part of the reactive power service it requires. We will continue to require reactive power service to be provided by and purchased from the transmission provider. However, a transmission customer may satisfy part of its obligation through self-provision or purchases from generating facilities under the control of the control area operator. The transmission customer's service agreement should specify all reactive supply arrangements.

We deny the California DWR and TAPS request that customer-owned generation facilities that are *available* to supply reactive power should automatically receive a credit. However, as the Final Rule states, a customer may reduce the charge for this service to the extent it can reduce its requirement for reactive power supply. We do not believe a transmission customer can satisfy all of its reactive requirements or allow the transmission provider to avoid

[165] FERC Stats. & Regs. at 31,716–17; *mimeo* at 239.

[166] *See also* Cajun. Cajun notes that it does and could continue to provide at least a portion of reactive power.

[167] *See also* APPA.

[168] The location and operating capabilities of the generator will affect its ability to reduce reactive power requirements.

investment in reactive power related facilities. Concerning the other request of TAPS, we will not require that the supply of reactive power be on a gridwide or regionwide basis. Because reactive power must be supplied near the point of need, we are not persuaded that gridwide supply is feasible.

c. Energy Imbalance Service

In the Final Rule, the Commission concluded that Energy Imbalance Service must be offered for transmission within and into the transmission provider's control area to serve load in the area.[169] However, the Commission noted, a transmission customer can reduce or eliminate the need for energy imbalance service in several ways.

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. For minor hourly differences between the scheduled and delivered energy, the transmission customer is allowed to 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. A minor difference is one for which the actual energy delivery differs from the scheduled energy by less than 1.5 percent, except that any hourly difference less than one megawatt-hour is also considered minor. Thus, the Final Rule established an hourly energy deviation band of ±/1.5 percent (with a minimum of 1 MW) for energy imbalance. The transmission customer must compensate the transmission provider for an imbalance that falls outside the hourly deviation band and for accumulated minor imbalances that are not made up within 30 days.

(1) Description of Energy Imbalance

Rehearing Requests

North Jersey asserts that the definitions of Energy Imbalance Service and Backup Supply Service are conflicting and need clarification. North Jersey proposes that Energy Imbalance Service be clarified to state that a transmission provider will be required to supply power to a customer ''within the dispatch period of the transmission provider's tariff.'' It states that this assures power when a customer is unable to change its nominations to match its generation capabilities. On the other hand, North Jersey states that Backup Supply Service should be the supply of power for a period longer than the tariff dispatch period.

NIMO asserts that the Commission should recognize that there is another type of Energy Imbalance Service. If a generator is located in one control area, but transfers the power to load in another control area, there is a potential mismatch between the amount of power scheduled for delivery by the generator and the amount it actually provides to the operator of the control area where it is located.

Nebraska Public Power District (NPPD) states that allowing third parties to provide Energy Imbalance Service and Regulation and Frequency Response Service could jeopardize system reliability. It argues that the transmission provider must have the right to approve the third party provider of these services and the right to physically meter the loads located out of the transmission provider's control area or otherwise monitor these services to be assured that they are provided satisfactorily.

NCMPA argues that because of the potential for abuse, the Commission should grant an exemption from an energy imbalance charge if the source of the energy shortfall is a generating resource that has been turned over to the transmission provider's dispatching control for meeting control area requirements.

Commission Conclusion

We clarify that Energy Imbalance Service is used to supply energy for mismatches between scheduled deliveries and actual loads that may occur over an hour. We do not intend it to be used as a substitute for operating reserves when there is an outage of generation supply or transmission. The Final Rule states that if a customer uses either type of operating reserve, it must expeditiously replace the reserve with backup power to reestablish required minimum reserve levels.[170]

Order No. 888 specifies that there is no obligation on the transmission provider to provide power to the customer for a ''time longer than specified in the tariff'' for the customer's own backup supply to be made available.[171] The order also states that ''any arrangements for the supply of such service [*i.e.*, Backup Supply Service] by the transmission provider should be specified in the customer's service agreement.''[172] We revise the first statement to clarify that the transmission customer's service agreement, not the tariff, should specify any arrangements for backup service by the transmission provider, including the time within which backup power supply will be made available. The time should correspond to the time necessary to restore operating reserves that is generally accepted in the region and consistently followed by the transmission provider.

NIMO asserts that two types of energy imbalance can occur if the generator and the load are in different control areas. These are (1) a mismatch between the energy scheduled to be received in the load's control area and the actual hourly energy consumed by the load, and (2) a mismatch between energy scheduled for delivery from the generator's control area and the amount of energy actually generated in the hour. The Energy Imbalance Service in the Final Rule applies to the first case only. Although we agree that the second type of mismatch can occur, we will not designate as Energy Imbalance Service a mismatch between energy scheduled and energy generated. Energy Imbalance Service in this Rule applies only to the obligation of the transmission provider to correct the first type of energy mismatch, one caused by load variations.

In general, 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. The Energy Imbalance Service that we require as our ancillary service has a bandwidth appropriate for load variations and should have a price for exceeding the bandwidth that is appropriate for excessive load variations. Although NIMO states correctly that, where two control areas are involved, there can also be a mismatch between energy scheduled and energy generated, NIMO has not explained why this mismatch should have the same bandwidth and price as our Energy Imbalance Service. Indeed, we believe it should not.

A generator should be able to deliver its scheduled hourly energy with precision. If we were to allow the generator to deviate from its schedule by 1.5 percent without penalty, as long as it returned the energy in kind at another time, this would discourage good generator operating practice. A generation supplier could intentionally generate less power when its generating cost is high and make it up when its cost is lower if the second type of mismatch is included in our Energy Imbalance Service. Instead, a generator will have an interconnection agreement with its

[169] FERC Stats. & Regs. at 31,717; *mimeo* at 240.

[170] Order No. 888 imposes no obligation on the transmission provider to furnish replacement power on a long-term basis if the customer loses its source of supply.

[171] FERC Stats. & Regs. at 31,711; *mimeo* at 222.

[172] FERC Stats. & Regs. at 31,711; *mimeo* at 223.

transmission provider or control area operator, and we expect that this agreement will specify the requirements for the generator to meet its schedule, and for any consequence for persistent failure to meet its schedule. This agreement will be tailored to the parties' specific standards and circumstances, and, although such arrangements must not be unduly preferential or discriminatory (*e.g.*, must be comparable for all wholesale sellers, including the transmission provider's own wholesale sales), we prefer not to set these standards generically for all parties.[173]

We disagree with NCMPA's argument regarding an exemption from Energy Imbalance Service when the control area operator controls the generating resource. As discussed above and in the Final Rule, energy imbalance results from a mismatch between a scheduled receipt and actual load in the control area of the transmission provider. Energy imbalance can occur if the actual load differs from the scheduled receipt regardless of who controls the generating resource.

As specified in the Final Rule, to ensure the reliability of the power system, a transmission customer is obligated to obtain Energy Imbalance Service and Regulation and Frequency Response Service for its transactions. We clarify for NPPD that the transmission customer may not decline the transmission provider's offer of these ancillary services unless it demonstrates to the transmission provider that it has acquired the services from another source. This demonstration must show that the customer's alternative arrangement for ancillary services is adequate and consistent with Good Utility Practice. The transmission customer's service agreement should specify any alternative arrangements for the provision of these (or any other) ancillary services.

(2) Energy Imbalance Bandwidth

As explained above, Schedule 4 (Energy Imbalance Service) of the tariff allows the transmission provider to charge a transmission customer serving load in its control area for taking an amount of energy in any hour that is 1.5 percent more or less than the amount of energy scheduled for that hour. In the pro forma tariff, the minimum amount of energy that can be assessed a charge in an hour is one megawatt-hour.

Rehearing Requests

Several entities argue that this energy imbalance bandwidth is too narrow and should be increased.[174] APPA asserts that the narrow bandwidth imposes obligations on the transmission customer that the transmission provider does not impose on itself.[175] TAPS argues that the 1.5 percent bandwidth ''makes no sense because it simply imposes a penalty for existence as a small utility.'' Redding states that the 1.5 percent energy imbalance bandwidth is not appropriate for transmission to a small utility that does not operate a control area. In opposing the narrow bandwidth, TDU Systems notes that metering error is typically within a range of ±2 percent. It further argues that it is impossible for smaller systems with low load factors, larger load swings, and the need to change the output quickly for a single unit to operate within the narrow bandwidth. Others assert that a too-narrow bandwidth creates a burdensome level of billings unless schedule changes are permitted more frequently than hourly.[176] They fear that meeting the 1.5 percent bandwidth would require expensive dynamic scheduling.

Some entities recommend a particular alternative bandwidth.[177] TDU Systems suggests a sliding scale as follows. There would be a bandwidth of ±5 percent of scheduled energy for transactions of 500 MW or less, decreasing to ±1.5 percent for transactions of 5,000 MW or more, with a minimum bandwidth of ±5 MWh in all cases. Alternatively, TDU Systems says that network customers could be entitled to a bandwidth equal to their load ratio share of the amount (not percentage) of their transmission provider's inadvertent interchange, again subject to a minimum of 5 MWh. TAPS recommends that the deviation bandwidth be changed to 6 percent of the transmission customer's daily peak demand, with a minimum bandwidth of 4 MWh.

NRECA proposes an alternative approach (previously set forth in its comments on the proposed rule): a customer's ''energy compensation balance'' should be determined for each hour based on the net energy deviation from the ''bandwidth base,'' which NRECA defines as the greater of (i) the customer's total on-line and available generator capacity associated with the generation dispatched, or (ii) the sum of a customer's maximum hourly demands at each of its recipient interfaces. NRECA states that its proposal sets forth separate compensation based on whether there is an overdelivery or an underdelivery outside a five percent bandwidth.

Wabash argues that the Commission should use a deviation bandwidth based on a period other than a single hour; for example, use a known historical number, such as the maximum hourly load during the previous calendar year. Wabash states that if a larger bandwidth is not adopted, the Commission should permit a transmission customer that is purchasing spinning or supplemental operating reserves as an ancillary service to use those purchases as the basis for an expanded deviation bandwidth. In addition, Wabash asks the Commission to clarify that an imbalance resulting from a system emergency situation caused by loss or failure of facilities should be counted as ''inadvertent loads'' and repaid in like hours at mutually agreed times and pay-back amounts.

Redding points out that the NERC (A2 Criterion) establishes a constant bandwidth for every hour of the year and should be used instead. For energy imbalances of less than 1.5 percent, Schedule 4 of the tariff allows the energy to be returned in kind within 30 days, after which payment must be made. Redding argues that the 30-day period should be deleted. Instead the Commission should follow current industry practice of allowing reasonable deviations to be carried forward into the next month so as to avoid an accounting nightmare. Finally, Redding argues that the bandwidth for network service should apply to the entire network load and not to a ''scheduled transaction.''

Wisconsin Municipals asks the Commission to clarify that if parties have reached a settlement that establishes a wider band, the transmission provider may not use Order No. 888 to avoid this settlement obligation.

TAPS argues that any charges for exceeding the bandwidth should be cost-based and compensation should be symmetrical for over-and under-deliveries.[178] TAPS further argues that

[173] Many provisions regarding the reliable operation and performance of both generation and load will be included in supply interconnection agreements and transmission customer service agreements. The fact that we have designated six services as necessary to prevent undue discrimination in transmission service should not be interpreted as our having set out a complete set of interconnected operations services and conditions necessary for reliable and orderly bulk power system management.

[174] *E.g.*, APPA, NRECA, Blue Ridge, Cooperative Power, Wabash, TDU Systems, Redding, TAPS.

[175] *See also* TDU Systems.

[176] *E.g.*, NRECA, Blue Ridge, Cooperative Power, Wabash.

[177] *E.g.*, TDU Systems, TAPS, NRECA, Wabash, Redding.

[178] On the other hand, Wabash argues that pursuant to industry practice, overdeliveries should be treated differently than underdeliveries outside

Continued

the bandwidth should not be applied by transaction, and customers should not have to pay for imbalances caused by transmission provider dispatch mistakes.

TDU Systems states that public utilities should be placed on notice that they will not be permitted to collect 100 mills per kWh for energy supplied by a customer in excess of its schedules, as some have sought in tariffs already filed.

Commission Conclusion

Energy Imbalance Service includes a bandwidth to promote good scheduling practices by transmission customers. It is important that the implementation of each scheduled transaction not overly burden others.

We do not agree with APPA that the bandwidth imposes an obligation on the transmission customer that the transmission provider does not impose on itself. The Final Rule treats all wholesale customers comparably. The transmission provider must also use its pro forma tariff and apply the same bandwidth for sales to its wholesale customers.

Many commenters assert that the energy imbalance bandwidth of ±1.5 percent is too narrow and is difficult to meet for small utilities. Several propose an alternative bandwidth or a larger minimum deviation. We believe that the bandwidth included in the Final Rule pro forma tariff is consistent with what the industry has been using as a standard and is as close to an industry standard as anyone can set at this time. However, we will set a larger minimum deviation to meet the needs of small customers. The minimum energy imbalance is now two megawatt-hours per hour (2 MW minimum in the pro forma tariff). This adequately addresses the concerns raised by small utilities because they may exceed the bandwidth without exceeding this minimum. For example, a transmission customer that transfers less than 133 MW (1.5 percent of 133 MW is 2 MW, the minimum energy imbalance) has a larger percentage bandwidth than ±1.5 percent. The bandwidth set forth in the pro forma tariff provides a needed incentive for a transmission customer to deliver an amount of energy each hour that is reasonably close to the amount scheduled, while at the same time recognizing the needs of small utilities. To help customers with the difficulty of forecasting loads far in advance of the hour, the Final Rule pro forma tariff permits schedule changes up to twenty minutes before the hour at no charge. By updating its schedule before the hour begins, a transmission customer should be able to reduce or avoid energy imbalance and associated charges. However, we will allow the transmitting utility and the customer to negotiate and file another bandwidth more flexible to the customer, subject to a requirement that the same bandwidth be made available on a not unduly discriminatory basis.

We disagree with Wabash's request to require a transmission provider to expand its energy imbalance bandwidth for a transmission customer purchasing spinning and supplemental reserves. Unlike Energy Imbalance Service, which treats deviations between scheduled and actual hourly energy deliveries, spinning and supplemental reserves provide generating capacity that responds to contingency situations (*e.g.*, loss or failure of facilities). Order No. 888 requires a transmission customer to obtain these operating reserve ancillary services for its transactions. Therefore, Wabash is simply requesting a larger energy imbalance bandwidth. We have selected the bandwidth to promote good scheduling practices by transmission customers. A larger bandwidth may introduce poor operating practices that could affect the reliability of the system. If the Energy Imbalance Service bandwidth were larger, energy supplied within this expanded bandwidth could be provided from reserve capacity. Some reserve capacity may not then be available when needed for system reliability. However, as stated in the Final Rule, we will allow a transmission provider to assemble packages of ancillary services (not bundled with basic transmission service) that can be offered at rates that are less than the total of individual charges for the services if purchased separately.[179]

In response to Wabash's other concern, we believe that emergency situations caused by loss or failure of facilities should be addressed in the transmission customer's service agreement (or the generation supplier's separate interconnection agreement) and not as part of Energy Imbalance Service.

In response to Redding's statement that the NERC (A2 criterion) establishes a constant bandwidth for imbalances, we note that NERC has set a standard for a kind of deviation that is different from our Energy Imbalance Service. NERC's bandwidth is for inadvertent interchange between a control area and all other control areas. Redding has presented no reason that our Energy Imbalance Service bandwidth should be the same as NERC's inadvertent interchange bandwidth. Regarding its concern about the in-kind repayment period, we note that Schedule 4 does not always require a 30-day period for in-kind repayment of energy imbalances; it also permits a term that the transmission provider consistently follows and is generally accepted in the region. In addition, we clarify that the bandwidth for network service applies to the entire network load.

With respect to Wisconsin Municipals' request, we clarify that the Final Rule does not require parties to a contract that went into effect prior to July 9, 1996 to stop using a wider bandwidth established by settlement. However, service provided pursuant to a settlement that was expressly approved subject to the outcome of Order No. 888 on non-rate terms and conditions must be revised in the subsequent compliance filing to reflect the language contained in the pro forma tariff.[180] Subsequent to the compliance tariff filing, public utilities are free to file under section 205 to revise the tariffs (*e.g.*, to reflect various settlement provisions) and customers are free to pursue changes under section 206.[181]

In response to arguments regarding the price of Energy Imbalance Service, we note that the Final Rule intentionally does not provide detailed pricing requirements. We require the transmission provider to determine and apply to the Commission for appropriate rates for Energy Imbalance Service as part of its transmission tariff. Transmission customers may address any disagreements with a specific charge in the company's transmission rate case.

2. Ancillary Services Obligations

In the Final Rule, the Commission distinguished two groups or categories of ancillary services: (1) services that the transmission provider is required to provide to all of its basic transmission customers under the tariff, and (2) services that the transmission provider is required to offer to provide only to transmission customers serving load in the provider's control area. The Commission required a transmission provider that operates a control area to provide the first group of ancillary services and the transmission customer

the deviation band. It adds that the rate for underdeliveries should be cost-based.

[179] FERC Stats. & Regs. at 31,719; *mimeo* at 246.

[180] *See* Order on Non-Rate Terms and Conditions, 77 FERC ¶ 61,144 at 61,538 (1996). The Commission explained:

Order No. 888 required all tariff compliance filings to contain non-rate terms and conditions identical to the pro forma tariff, with a limited exception for regional practices, and with four attachments where the utility could propose specific inserts.

[181] FERC Stats. & Regs. at 31,770 n.514; *mimeo* at 399 n.514.

to purchase these services from the transmission provider. The Commission required a transmission provider to offer to provide the ancillary services in the second group to transmission customers serving load in the transmission provider's control area. The Commission required the transmission customer serving load in the transmission provider's area to acquire these services, but allowed the transmission customer to do so from the transmission provider, a third party or self-supply.

If the transmission provider is a public utility providing basic transmission service, but is not a control area operator, the Commission allowed the transmission provider to fulfill its obligation to provide, or offer to provide, ancillary services by acting as the customer's agent. In this case, if the control area operator is a public utility, the Commission required the control area operator to offer to provide all ancillary services to any transmission customer that takes transmission service over facilities in its control area whether or not the control area operator owns or controls the facilities used to provide the basic transmission service.

a. Obligation of a Control Area Utility

Rehearing Requests

Carolina P&L asks the Commission to clarify that the transmission provider is not required to provide control area services to another utility operating a control area that simply chooses not to provide for its own control area obligations. It argues that this is not justified in a competitive bulk power market.

Maine Public Service asserts that a transmission provider that is not a NERC-recognized control area can provide ancillary services from its own facilities. It asks that the Commission clarify that this is permissible. At a minimum, Maine Public Service states that the Commission must allow transmission providers on a case-by-case basis to establish that they provide ancillary services even if they are not NERC-recognized control areas or do not satisfy the Commission's definition (citing the initial decision in Maine Public Service Company, 74 FERC ¶ 63,011 (1996)).

Similarly, California DWR states that it has been operating since 1983 as a quasi-control area, self-providing most, if not all, of the ancillary services it uses. It also notes that it provides such services to its utility transmission providers. California DWR argues that it is entitled to appropriate compensation for all ancillary services that it provides to its transmission providers or other parties.

Commission Conclusion

In response to Carolina P&L, we clarify that the Final Rule does not require a control area operator to provide control area services within another control area.

Except for the ancillary service called Scheduling, System Control and Dispatch,[182] the Final Rule does not preclude a transmission provider that is not a control area operator from offering ancillary services to its transmission customers.

Order No. 888 requires that a transmission customer obtain or provide ancillary services for its transactions. If a transmission customer can self-supply a portion of its requirement for ancillary services (other than Scheduling, System Control, and Dispatch Service), it should pay a reduced charge for these services. As with the transmission provider, a third party may offer ancillary services voluntarily to other customers if technology permits. However, simply supplying some duplicative ancillary services (*e.g.*, providing reactive power at low load periods or providing it at a location where it is not needed) in ways that do not reduce the ancillary services costs of the transmission provider or that are not coordinated with the control area operator does not qualify for a reduced charge. The transmission customer must make separate arrangements with the transmission provider or control area operator to supply its own ancillary services and specify such arrangements in its service agreement.

b. Obligation to Provide Dynamic Scheduling

Dynamic scheduling electronically moves a generation resource or load from the control area in which it is physically located to a new control area. In the Final Rule, the Commission concluded that it would not require the transmission provider to offer Dynamic Scheduling Service to a transmission customer, although a transmission provider may do so voluntarily. If the customer wants to purchase this service from a third party, the Commission stated that the transmission provider should make a good faith effort to accommodate the necessary arrangements between the customer and the third party for metering and communication facilities.

Rehearing Requests

AMP-Ohio asks that the Commission clarify that the transmission provider is required to provide dynamic scheduling ''to the extent a transmission customer needs and is willing to pay for reasonably priced dynamic scheduling in order to support its operations, including in order to integrate its loads and resources located in more than one control area.'' Wisconsin Municipals also asks the Commission to clarify that dynamic scheduling must be provided if technically feasible and permitted by regional reliability practices.

Wisconsin Municipals further asks that the Commission clarify that if the transmission provider has agreed to provide dynamic scheduling in a settlement, it may not use its Order No. 888 implementation filing to void this obligation.

EEI asks that the Commission clarify the residual obligations of a control area utility to an entity that electronically leaves the control area via dynamic scheduling.

Commission Conclusion

In response to Amp-Ohio and Wisconsin Municipals, we note that dynamic scheduling is not a required ancillary service in Order No. 888, and we do not require a transmission provider to offer this service. However, nothing in the Final Rule precludes a transmission provider from offering it as a separate service. Furthermore, offering dynamic scheduling to integrate loads and resources in more than one control area is also not required.

Wisconsin Municipals' argument with respect to prior settlements has been previously addressed in Section IV.D.1.c.(2) (Energy Imbalance Service).

We clarify for EEI that, once dynamic scheduling is arranged, each of the two control areas has ancillary service responsibilities under the Rule. The reactive power obligations of the original control area remain and cannot be completely supplied by distant sources. Order No. 888 requires, in the case of dynamic scheduling, both control areas to provide the first two ancillary services in their respective control areas, that is, (1) Scheduling, System Control, and Dispatch Service and (2) Reactive Supply and Voltage Control from Generation Sources Service, and the new control area to offer the remaining ancillary services to the dynamically scheduled entity. In addition, the actual energy transfers between the two control areas will require basic transmission service. We

[182] As NERC and others pointed out in their comments on the proposed rule, this service can be provided only by the operator of the control area in which the transmission facilities used are located. FERC Stats. & Regs. at 31,716; *mimeo* at 238.

expect that any additional obligations of a control area operator to an entity that electronically leaves the control area via dynamic scheduling, such as backup procedures for the failure of telemetering equipment, will be set out in the transmission customer's service agreement.

c. Obligation As Agent

Rehearing Requests

A transmission provider must act as an agent to help the customer acquire ancillary services if the transmission provider cannot provide them itself. NRECA asks whether a non-public utility may collect a reasonable fee for its agency services in fulfilling its reciprocity requirement.

Commission Conclusion

While the Final Rule does not allow a public utility transmission provider acting as an ancillary services agent to collect a fee for its agency service, we do not have similar authority to deny a non-public utility the opportunity to charge a fee for providing an agency service. However, to the extent a non-public utility seeks to collect an agency fee from a public utility, it must meet our comparability requirements and charge a comparable fee to its own wholesale merchant function.

3. Miscellaneous Ancillary Services Issues

a. Transmission Provider as Ancillary Services Merchant

Rehearing Requests

Allegheny asserts that the sale of power in connection with ancillary services would make the transmission provider a wholesale merchant under the Commission's standards of conduct (citing section 37.3 of the Commission's Regulations). Allegheny asks that the Commission clarify that a transmission provider's employee responsible for providing ancillary services is not engaged in a wholesale merchant service that would trigger the functional separation requirement.

Commission Conclusion

We clarify that the transmission provider's sale of ancillary services associated with its provision of basic transmission service is not a wholesale merchant function for purposes of Order No. 889. This is because the provision of ancillary services is essential for providing transmission service. However, the sale of ancillary services not associated with the transmission provider's provision of basic transmission service is a wholesale function for purposes of Order No. 889. Thus, if an employee is marketing an ancillary service independent of the transmission provider's obligations to provide transmission service, *i.e.*, as a third party to another transmission provider's basic transmission service customer, the employee would be providing a wholesale merchant function and the Order No. 889 Standards of Conduct apply.

b. QF Receipt of Ancillary Services

Rehearing Requests

North Jersey argues that the Commission did not engage in reasoned decisionmaking in ruling that Real Power Loss Service is not an ancillary service. It asserts that this service must be provided by the transmission provider. North Jersey further argues that, because the Commission describes the furnishing of real power loss as a sale of power, this could prevent a PURPA qualifying facility (QF) from being a transmission service customer. North Jersey states that a QF faces power purchase and resell restrictions under the Commission's regulations. North Jersey asks that the Commission find that receipt of Real Power Loss Service from a third party to complete a transmission transaction is not a purchase and resale of power. In addition, North Jersey requests that the Commission clarify that receipt of ancillary services by a QF does not constitute a purchase and resale of electric power that would jeopardize its status as a QF (clarification also requested in ER95–791–000).[183]

Commission Conclusion

The Commission disagrees with North Jersey's assertion that Real Power Loss Service should be an ancillary service that must be provided by the transmission provider. As stated in the Final Rule, it is not necessary for the transmission provider to supply Real Power Loss Service to effect a transmission service transaction. Although the transmission customer is responsible for losses associated with its transmission service, supply of losses is purely a generation service that can be (1) self supplied; (2) purchased from the transmission provider, if it offers this service; or (3) purchased from a third party.

We clarify that a QF arrangement for receipt of Real Power Loss Service or ancillary services from the transmission provider or a third party for the purpose of completing a transmission transaction is not a sale-for-resale of power by a QF transmission customer that would violate our QF rules.

c. Pricing of Ancillary Services

In the Final Rule, the Commission concluded that it would consider ancillary services rate proposals on a case-by-case basis and offered general guidance on ancillary services pricing principles.[184]

Rehearing Requests

NRECA and TDU Systems argue that there should be truth in transmission pricing so that the rate is clearly identified as including or excluding ancillary services.

AEP asserts that if a purchaser of ancillary services has alternative suppliers of these services, then either the transmission provider should not be required to provide those services or it should be able to charge market rates for them. Otherwise, according to AEP, the market is skewed in favor of the customer.

Illinois Power argues that if a transmitting utility demonstrates that it incurs incremental costs from its obligation to offer to provide the required ancillary services, it should be permitted to recover such costs through an adjustment to base transmission rates.

Commission Conclusion

The Final Rule requires unbundling of individual ancillary services from basic transmission service. We point out to NRECA and TDU Systems that the transmission provider must post and update prices for basic transmission and each ancillary service on its OASIS. As discussed below in Section IV.G.1.h. (Discounts), the Commission is revising its policy regarding the discounting of the price of transmission services. There, we establish three principal requirements for discounting basic transmission service.[185] We clarify here that these principal requirements apply to discounts for ancillary services provided by the transmission provider in support of its provision of basic transmission service. However, because ancillary services are generally not path-

[183] In Docket No. ER95–791 the Commission ruled that this issue was not part of the hearing and that North Jersey should file for a declaratory order to resolve the matter.

[184] FERC Stats. & Regs. at 31,720–21; *mimeo* at 250–52.

[185] In brief, these are that (1) any offer of a discount made by the transmission provider must be announced to all potential customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for one's own use or for 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. In addition to these three principal requirements, we also require that a discount agreed upon for a path must be extended to certain other paths described in Section IV.G.1.h.

specific, 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. In addition, if a transmission provider offers any rate or packaged ancillary service discounts, it must post them on its OASIS and make them available to affiliates and non-affiliates on a basis that is not unduly discriminatory. In this manner, any discounting of ancillary service prices is visible to all market participants. We will require that, as soon as practicable, any ''negotiation'' of discounts between a transmission provider and potential transmission (and ancillary) service customers should take place on the OASIS.[186]

We continue to require a transmission provider to provide or offer to provide the six ancillary services, even if the transmission customer has some alternative suppliers. We distinguished these six services from others (*e.g.*, Real Power Loss Services) for which many suppliers are typically available. In some cases, only the transmission provider can provide the ancillary service; in other cases too few providers are available to create a market for these services. Further, we were persuaded by the comments of NERC and others that these services are essential for reliability; if a customer must obtain these services to obtain transmission service there must be a default provider of these services. However, market-based rates for some of the ancillary services may be appropriate if the seller lacks market power for such services. Market power issues regarding ancillary services have to be addressed before market-based rates for ancillary services can be approved, as requested by AEP. We will consider market-based rates for ancillary services on a case-by-case basis.

In reply to Illinois Power, we agree that the transmission provider may incur incremental costs from its obligation to offer to provide ancillary services. We believe, however, these costs should be included in the price for those services. Order No. 888 requires the transmission provider to unbundle the cost of ancillary services from the base transmission rate. A rebundling of these costs with the base transmission rate, as Illinois Power requests, would not satisfy the unbundling requirement.

E. Real-Time Information Networks

In the Final Rule, the Commission concluded that in order to remedy undue discrimination in the provision of transmission services it is necessary to have non-discriminatory access to transmission information, and that an electronic information system and standards of conduct are necessary to meet this objective.[187] Therefore, in conjunction with the Final Rule, the Commission issued a final rule adding a new Part 37 that requires the creation of a basic OASIS and standards of conduct.

Rehearing Requests

Rehearing requests raising arguments with respect to specific aspects of OASIS and standards of conduct are addressed in Order No. 889–A, issued concurrently with this order.

F. Coordination Arrangements: Power Pools, Public Utility Holding Companies, Bilateral Coordination Arrangements, and Independent System Operators

In the Final Rule, the Commission explained that its requirement for non-discriminatory transmission access and pricing by public utilities, and its specific requirement that public utilities unbundle their transmission rates and take transmission service under their own tariffs, apply to all public utilities' wholesale sales and purchases of electric energy, including coordination transactions.[188] While the Commission ''grandfathered'' certain existing requirements agreements and non-economy energy coordination agreements, it also determined that certain existing wholesale coordination arrangements and agreements must be modified to ensure that they are not unduly discriminatory. The Commission then discussed (as set forth further below) how and when various types of coordination agreements will need to be modified, and when public utility parties to coordination agreements must begin to trade power under those agreements using transmission service obtained under the same open access transmission tariff available to non-parties.

The Commission explained that it was addressing four broad categories of coordination arrangements and accompanying agreements: ''tight'' power pools, ''loose'' power pools, public utility holding company arrangements, and bilateral coordination arrangements.

In addition, the Commission explained that ISOs may prove to be an effective means for accomplishing comparable access and, accordingly, provided guidance on minimum ISO characteristics.

1. Tight Power Pools

The Commission required public utilities that are members of a tight pool to file, within 60 days of publication of the Final Rule in the Federal Register, either: (1) an individual Final Rule pro forma tariff; or (2) a joint pool-wide Final Rule pro forma tariff.[189] However, the Commission required them to file a joint pool-wide Final Rule pro forma tariff no later than December 31, 1996, and to begin to take service under that tariff for all pool transactions no later than December 31, 1996.[190] The Commission also required the public utility members of tight pools to file reformed power pooling agreements no later than December 31, 1996 if the agreements contain provisions that are unduly discriminatory or preferential.

If a reformed power pooling agreement allows members to make transmission commitments or contributions in exchange for discounted transmission rates, the Commission indicated that the pool may file a transmission tariff that contains an access fee (or file a higher transmission rate) for non-transmission owning members or non-members, justified solely on the basis of transmission-related costs.

Rehearing Requests

Consumers Power asks the Commission to clarify that Order No. 888 does not preclude the Michigan Electric Coordinated Systems (MECS) from being in compliance by removing all transmission functions from pool control and allowing pool members or the pool to take transmission service from transmission-owning pool members under their open access tariffs. It asserts that this would be an interim placeholder alternative while retail deliberations continue in Michigan. Furthermore, as one of the two members of MECS, Consumers Power indicates that it would be willing to consider further modifications that would liberalize membership criteria during the transition period if the Commission otherwise clarifies that the MECS Pool is in compliance with Order No. 888.

[186] ''Negotiation'' would only take place if the transmission provider or potential customer seeks prices below the ceiling prices set forth in the tariff.

[187] FERC Stats. & Regs. at 31, 722; *mimeo* at 255–56.

[188] FERC Stats. & Regs. at 31,725–27; *mimeo* at 266–70.

[189] FERC Stats. & Regs. at 31,727–28; *mimeo* at 270–72.

[190] By notice issued September 27, 1996, the Commission extended the date by which public utilities that are members of tight power pools must take service under joint pool-wide open access transmission tariffs from no later than December 31, 1996 to 60 days after the filing of their joint pool-wide section 206 compliance tariff.

NY Municipals request that the Commission clarify that, particularly if generation services are to be provided at market-based rates, monopoly transmission services must continue to be provided at cost-based rates (raised in connection with the NYPP). They also ask that the Commission clarify that joint pool-wide tariffs must incorporate transmission rates that are uniform (non-pancaked) and strictly based on the embedded costs of the transmission facilities and related transmission expenses. Moreover, NY Municipals argue that transmission owners should receive a credit based on the depreciated costs of their transmission facilities.

TAPS also asks the Commission to clarify that pool-wide and system-wide tariffs must contain non-pancaked rates.

Commission Conclusion

While Consumers Power's proposal to remove transmission functions from pool control, if implemented in a non-discriminatory fashion, would satisfy the comparability requirements of Order No. 888, the Commission encourages Consumers Power to pursue a pool-wide tariff.[191]

NY Municipal Utilities' concern that rates for transmission service will not be priced at cost-based rates is ill-founded. While Order No. 888 does not establish any specific pricing methodology for tariff transmission service, the Commission expects all transmission rate proposals filed on compliance to be cost based and to meet the standard for conforming proposals set out in the Commission's Transmission Pricing Policy Statement. (*See* 18 CFR 2.22).

Regarding NY Municipal Utilities' and TAPS's requests for a uniform tariff with non-pancaked rates, Order No. 888 does not require a non-pancaked rate structure unless a non-pancaked rate structure is available to pool members. Although the Commission has encouraged the industry to reform transmission pricing, the Commission's current policy does not mandate a specific transmission rate structure.

With regard to NY Municipal Utilities' concern about market-based rates for generation, public utility owners of existing NYPP generation are not eligible to charge market-based power sales rates absent Commission approval. Order No. 888 allows market-based rates only if the seller in a case-specific filing demonstrates it meets the Commission's well-established criteria of showing that it and its affiliates do not have or have adequately mitigated transmission market power and generation market power, that there are no other barriers to entry, and there is no evidence of affiliate abuse or reciprocal dealing. With regard to requests to make market-based sales from *new* generation, the seller does not have to submit evidence of generation market power in long-run bulk power markets (subject to challenge where specific evidence can be presented);[192] however, for sales from existing generation at market-based rates, the applicant must demonstrate that it lacks, or has fully mitigated, generation market power.[193]

In response to NY Municipals' request that transmission owners that contribute transmission facilities to a power pool should receive a rate credit based on the depreciated costs of those transmission facilities, we agree that this is one possible way of reflecting a pool member's contributions or commitments of transmission facilities. However, NY Municipals has provided no rationale as to why we should limit the broader approach we adopted in Order No. 888 to this single mechanism.[194]

2. Loose Pools

In the Final Rule, the Commission found that public utilities within a loose pool must file, within 60 days of publication of the Final Rule in the Federal Register, either: (1) an individual Final Rule pro forma tariff; or (2) a pool-wide Final Rule pro forma tariff.[195] However, the Commission required that they file a joint pool-wide Final Rule pro forma tariff no later than December 31, 1996, and begin to take service under that tariff for all pool transactions no later than December 31, 1996.[196] The Commission also required that the public utility members of loose pools file reformed power pooling agreements no later than December 31, 1996 if the agreements contain provisions that are unduly discriminatory or preferential. They also must file a joint pool-wide tariff no later than December 31, 1996.

If a reformed pooling agreement allows members to make transmission commitments or contributions in exchange for discounted transmission rates, the Commission determined that the pool may file a transmission tariff that contains an access fee (or a higher transmission rate) for non-transmission owning members or non-members, justified solely on the basis of transmission-related costs.

Rehearing Requests

Union Electric asserts that the definition of loose pools is so vague that many public utilities, regional organizations and multi-lateral arrangements, which are not actually pools, may incorrectly be deemed loose pools by third parties. Thus, Union Electric asks the Commission to clarify that members or parties to multi-lateral arrangements only need to offer transmission services pursuant to their own individual company tariffs.

EEI asks the Commission to clarify the nature of the tariffs that loose pools may file to comply with the Rule to ensure that the members are not required to file tariffs for services that they do not now provide. EEI also requests that, where members of loose pools currently provide transmission services to each other, they may continue to provide such services to each other under each member's individual pro forma tariff in lieu of a pool-wide tariff (provided that those services are made available to all eligible entities on a non-discriminatory basis). Similarly, Montana Power argues that members of loose pools should be allowed to meet comparability by filing individual open access tariffs, without having to file a pool-wide tariff.[197]

Public Service Co of CO asserts that the primary purpose of the Inland Power Pool is to provide for reserve sharing during emergency conditions, although the pool agreement also allows for economy transactions. It argues that another way to comply with the Rule should be to eliminate the economy energy schedule of the Inland Power Pool Agreement. Moreover, Public Service Co of CO argues that given the number of non-jurisdictional entities within the Inland Power Pool, it may be impossible to agree on a pool-wide tariff. El Paso adds that Inland Power Pool should not be treated as a loose

[191] It is not clear from the rehearing request exactly how the current members of MECS are proposing to remove all transmission functions from pool control and to take transmission service under their individual open access tariffs. For example, this may preclude the continuation of joint economic dispatch of generating facilities belonging to Consumer Power and Detroit Edison, which the rehearing request appears to assume would continue. However, the Commission will address the adequacy of any such proposal in the context of the appropriate compliance filings.

[192] FERC Stats. & Regs. at 31,657; *mimeo* at 64–65; section 35.27.

[193] FERC Stats. & Regs. at 31,660; *mimeo* at 73–74.

[194] *See* FERC Stats. & Regs. at 31,727–28; *mimeo* at 271–72.

[195] FERC Stats. & Regs. at 31,728; *mimeo* at 272–74.

[196] By notice issued September 27, 1996, the Commission extended the date by which public utility members of loose power pools must take service under joint pool-wide open access transmission pro forma tariffs from no later than December 31, 1996 to 60 days after the filing of their joint pool-wide section 206 compliance tariff.

[197] *See also* Public Service Co of CO.

pool because it functions as a reserve sharing mechanism and not as a pool.

Utilities For Improved Transition asks the Commission to clarify that pool members or members of other entities do not have to provide more transmission services than they already provide on a voluntary basis to each other. It contends that there is no record to support a broader obligation and would cause massive disruption and the disintegration of many existing pools. Utilities For Improved Transition maintains that pools should have substantial leeway to develop arrangements reflecting their diverse memberships and the diverse contributions made.

VEPCO seeks clarification whether the Commission intended to impose the single-system tariff requirement only with respect to multilateral agreements that provide for system-wide transmission rates for the parties to the agreements.

TAPS asks the Commission to clarify that section 35.28(c)(3) includes all pools and all holding company systems, as well as any multi-lateral agreement so long as the multi-lateral agreement explicitly or implicitly addresses transmission (*e.g.*, by providing for a transaction without assessing transmission costs in connection with that transaction).

Commission Conclusion

In response to parties seeking clarification of the definition of a loose pool, the Commission clarifies that a loose pool is any multilateral arrangement, other than a tight power pool or a holding company arrangement, that explicitly or implicitly contains discounted and/or special transmission arrangements, that is, rates, terms, or conditions. The Commission requires public utilities that are members of a loose pool to either (1) reform their pooling arrangements in accordance with Order No. 888 or (2) excise *all* discounted and/or special arrangements transmission service from the pooling arrangement. That is, in the latter case the members could continue to provide other services (*e.g.*, generation), but would cease to be a loose pool for purposes of Order No. 888.

The primary goal of Order No. 888's requirements for pooling arrangements, including ''loose'' pools, is to ensure comparability regarding transmission services that are offered on a pool-wide basis. We believe comparability for loose pools can be achieved if pooling agreements are modified: (1) to allow open membership and (2) to make the transmission service in the loose pool agreement available to others. While the Commission encourages pool-wide transmission tariffs that offer the full range of transmission services included in the pro forma tariff, we will not require, under the comparability principles of Order No. 888, that pool members offer to third parties transmission services that they do not provide to themselves on a pool-wide basis. For example, if existing loose pool members do not offer network services to each other, they do not have to expand the pool services to offer network services to themselves or any third parties. Additionally, we do not find it to be unduly discriminatory to provide some pool-wide transmission services to members under a pooling agreement and to provide other transmission services to members under the individual tariff of each member, as long as members and non-members have access to the same transmission services on a comparable basis and pay the same or a comparable rate for transmission.[198]

The Commission notes that the Inland Power Pool agreement provides for non-firm transmission service (Service Schedule D) for emergency service, scheduled outage service, and economy energy service. The Inland Power Pool agreement provides members preferential transmission rates for deliveries of emergency service, *i.e.*, members will provide free non-firm transmission service at a higher priority than any other non-firm transactions. Such preferential service is not available to non-members. We consider any rates, terms or conditions of transmission service that favor members over non-members to be unduly discriminatory and preferential, whether embodied explicitly or implicitly in a loose pooling agreement. Pool members can either amend the agreement to provide comparable services to others and open the pool to new members, or amend the agreement to eliminate any preferential transmission availability and/or pricing.

In response to TAPS, the Commission agrees that Section 35.28(c)(3) applies to any pool, holding company system or multi-lateral agreement that contains explicit or implicit transmission rates, terms, or conditions.[199] For example, if a utility offers transmission without charge as part of such an agreement, it must offer transmission to all parties requesting a similar service either without charge or at an access fee or other transmission rate that comparably reflects transmission-related costs borne by members of the agreement.[200]

3. Public Utility Holding Companies

In the Final Rule, the Commission required that holding company public utility members, with the exception of the Central and South West (CSW) System, file a single system-wide Final Rule pro forma tariff permitting transmission service across the entire holding company system at a single price within 60 days of publication of the Final Rule in the Federal Register.[201]

With respect to CSW, the Commission directed the public utility subsidiaries of CSW to consult with the Texas, Arkansas, Oklahoma and Louisiana Commissions and to file not later than December 31, 1996 a system tariff that will provide comparable service to all wholesale users on the CSW System, regardless of whether they take transmission service wholly within ERCOT or the SPP, or take transmission service between the reliability councils over the North and East Interconnections.

The Commission gave public utilities that are members of holding companies an extension of the requirement to take service under the system tariff *for wholesale trades* between and among the public utility operating companies within the holding company system until December 31, 1996—the same extension it granted to power pools.[202] In addition, the Commission indicated that it may be necessary for registered holding companies to reform their holding company equalization agreement to recognize the non-discriminatory terms and conditions of transmission service required under the Final Rule pro forma tariff.

Rehearing Requests

FL Com asks the Commission to clarify whether it intends to require operating company members of a registered holding company to charge each other the same wheeling charge to be charged to others even though others pay nothing for transmission construction. FL Com argues that such

[198] See FERC Stats. & Regs. at 31,728; *mimeo* at 273–74.

[199] *See* FERC Stats. & Regs. at 31,726; *mimeo* at 268–69 (filing of open access tariffs by public utility pool members is not enough to cure undue discrimination in transmission if those entities can continue to trade with a selective group within a power pool; the same holds true for certain bilateral arrangements allowing preferential pricing or access) and FERC Stats. & Regs. at 31,727–28; *mimeo* at 270–272 (tight and loose pools must file *joint* pool-wide tariffs).

[200] *See* FERC Stats. & Regs. at 31,730; *mimeo* at 278.

[201] FERC Stats. & Regs. at 31,728–29; *mimeo* at 274–77.

[202] By notice issued September 27, 1996, the Commission extended the date by which public utilities that are members of holding companies must take service under their system-wide tariffs from December 31, 1996 to no later than March 1, 1997.

a charge would be inconsistent with the Commission's traditional treatment of public utility holding companies as a single entity.

AL Com asks the Commission to clarify that ''intra-holding company transactions in support of economic dispatch across a single integrated system should not be subjected to additional transmission charges, while transactions between operating companies for the benefit of wholesale customers not included within the definition of native load customer require distinct transmission charges.'' [203]

Southern asks the Commission to clarify that transactions between public utility operating subsidiaries within a holding company system for the benefit of native load customers fall within the network service for which they are assigned cost responsibility under the Final Rule tariff.

AEP asserts that the Commission has provided no reason for requiring holding companies to use the pro forma tariff for intra-pool transactions. AEP asks the Commission to clarify whether the Rule applies to AEP. It asserts that the Preamble states that all members of holding company systems must use the pro forma tariff for intra-system transactions, but the regulatory text requires only a member of a public utility holding company ''arrangement or agreement that contains transmission rates, terms or conditions * * *.'' AEP explains that the AEP System Interconnection Agreement and Transmission Agreement do not contain transmission rates, terms or conditions and the members do not offer transmission service to one another.

However, AEP argues that, if the Rule applies to AEP, Order No. 888 contains no explanation of why or how a different intra-pool allocation of transmission costs than would result from the pro forma tariff prejudices transmission users. It asserts that (1) AEP's allocation has been subject to extensive review over the last few years, (2) AEP treats itself as a single system, not as a collection of individual members, (3) each member carries its fair share of transmission costs, and (4) compliance with the Commission's requirement would be onerous. If the Commission does not remove this requirement, AEP requests waiver of the requirement.

Similarly, Allegheny Power asserts that its Power Supply Agreement (PSA) does not provide for ''wholesale trades.'' It argues that the PSA is immaterial to all transmission services, including intra-company exchanges. Because the PSA is an existing contract that the Final Rule does not propose to abrogate, Allegheny Power asserts that the PSA need not be reformed under the Final Rule. Allegheny states that it will provide new wholesale service to itself and others under its open access tariff which was accepted for filing on December 6, 1995 in Docket No. ER96–58.

Union Electric assumes that the ''rule is intended solely to mean that a holding company system would use the network integration part of the tariff, for its intra-system 'wholesale trades.' Indeed, if Union Electric and CIPS were required to take point-to-point service for their wholesale trades, they would be placed in an inferior and non-comparable position vis-a-vis customers on the Ameren tariff who will be entitled to single-system transmission service for a single or postage-stamp charge.'' (Union Electric notes that Union Electric and CIPS are currently seeking approval to merge, with the combined facilities being operated as the Ameren System.)

NU believes that Order No. 888 could be construed to require NU System Companies to charge each other as separate entities for transmission service in connection with intra-system cost allocations as if off-system wholesale sales had occurred. NU argues, however, that this is inconsistent with Commission precedent in treating the NU System Companies as a single integrated system and would give retail native load customers service inferior to that of wholesale native load (*i.e.*, network) customers. NU further argues that it will result in duplicative transmission charges for energy flows between the NU System Companies. Moreover, NU asserts that viewing NU as a single system for establishing transmission rates, but as separate companies with respect to energy flows that result from economic dispatch of their generation to native load is inconsistent with the treatment of multistate non-holding company utilities and is thus discriminatory.

Blue Ridge seeks clarification that, to avoid double payment for transmission, ''CSW must file its compliance filing resolving comparability issues and the appropriate CSW ERCOT transmission rate prior to September 1, 1996.'' Blue Ridge asserts that CSW must resolve a potential conflict between its rate structure and the new PUCT wheeling rule by September 1, 1996 (contemplated effective date for interim PUCT transmission rates).

Commission Conclusion

In requiring holding companies to file a pool-wide tariff, the Commission does not intend that transmission service provided by the operating subsidiaries to one another on behalf of their respective native loads be subjected to additional transmission charges. The Commission recognizes that the operating subsidiaries of a holding company bear cost responsibility for transmission facilities by virtue of ownership of such facilities. In many, if not all cases, transmission costs are equalized among operating subsidiaries through transmission equalization agreements (*e.g.*, AEP's Transmission Agreement).

However, the Commission does intend, pursuant to Order No. 888, that holding company operating subsidiaries take transmission service under the same tariff rates, terms, and conditions as third-party customers that seek transmission service over the holding company system. This applies to all holding company systems that rely upon the transmission facilities of the individual operating subsidiaries to support central economic dispatch—including AEP and Allegheny. However, as suggested by Southern and Union Electric, the Commission anticipates that transmission service for an operating subsidiary's native load would be treated as network service under the pro forma tariff. Accordingly, the CP demands of each operating subsidiary's native load would establish each operating subsidiary's transmission cost responsibility related to network service over the integrated transmission facilities of the holding company system.

Thus, in response to the AL and FL Commissions, Southern, and NU, intra-holding company transactions in support of economic dispatch would not be subjected to ''additional'' transmission charges.[204] The load ratio pricing mechanism of the network portion of the tariff should ensure that each operating company bears its proportionate share of transmission costs without jeopardizing or otherwise penalizing these types of intra-system transactions. Moreover, any off-system sales would have to be taken under the point-to-point provisions of the tariff. As we noted in Order No. 888, ''it may be necessary for registered holding companies to reform their holding

[203] AL Com at 1–4.

[204] The Commission notes that Order No. 888 requires that all third party tariff customers taking network or point-to-point service pay a transmission rate which reflects an appropriate share of transmission costs, including those related to transmission construction.

company equalization agreement to recognize the non-discriminatory terms and conditions of transmission service required under the Final Rule pro forma tariff.'' [205] However, nothing in Order No. 888 mandates any change to the method chosen for apportioning transmission revenues among the operating companies, which may be based, for example, upon equalizing transmission investment responsibility.

The concerns raised here by Blue Ridge are resolved on an interim basis because the PUCT has accepted the filing of CSW's Federal tariff as adequate in the Texas proceeding until differences between the Order No. 888 rate structure and the PUCT rate structure are resolved. If, CSW implements a new ERCOT transmission tariff in response to actions of the PUCT, then affected parties may bring any remaining concerns to the Commission's attention at that time through a section 206 complaint.

We note that the issue raised here by Blue Ridge is very similar to the one raised by Tex-La and East Texas Electric Cooperative, and addressed by the Commission's recent order, in *Houston Lighting & Power Co.*, 77 FERC ¶ 61,113 at 61,439 (1996). There, the Commission found that it would be premature to address this issue at that time, and noted that parties would have an opportunity to raise their concerns after the PUCT finalizes its ERCOT tariff.

4. Bilateral Coordination Arrangements

In the Final Rule, the Commission required that any bilateral wholesale coordination agreements executed after the effective date of the Final Rule would be subject to the functional unbundling and open access requirements set forth in the Rule.[206] In addition, the Commission required that all bilateral economy energy coordination contracts executed before the effective date of the Rule be modified to require unbundling of any economy energy *transaction* occurring after December 31, 1996. Moreover, the Commission permitted all non-economy energy bilateral coordination contracts executed before the effective date of the Rule to continue in effect, but subject to section 206 complaints.

To compute the unbundled coordination compliance rate, the Commission indicated that the utility must subtract the corresponding transmission unit charge in its open access tariff from the existing coordination rate ceiling. However, the Commission noted, if a utility's transmission operator offers a discounted transmission rate to the utility's wholesale marketing department or an affiliate for the purposes of coordination transactions, the same discounted rate must be offered to others for trades with any party to the coordination agreement. In addition, the Commission explained that discounts offered to non-affiliates must be on a basis that is not unduly discriminatory.

Rehearing Requests

SoCal Edison seeks clarification as to how Order No. 888 affects package agreements (*i.e.*, bilateral contracts that provide some or all of requirements service, coordination service, or transmission service). In particular, SoCal Edison asks (1) what specific functions of each must be modified to comply with Order No. 888; (2) whether a sale of non-firm energy made pursuant to a package agreement must comply with the unbundling requirements for coordination contracts; (3) whether the requirement to remove preferential transmission access or pricing provisions applies to existing or future transmission services provided pursuant to package agreements; if so, what is the deadline; and (4) whether the rulings with respect to *Mobile-Sierra* apply to package agreements.[207]

APPA argues that the Commission should require *all* coordination arrangements to be subject to Order No. 888. CCEM asserts that to the extent non-economy energy coordination agreements are allowed to remain bundled, they should be identified in connection with determinations of available transfer capacity and, because they should only be a transitional matter, should be subject to a sunset date of December 31, 1996.

According to Utilities For Improved Transition, requiring the subtraction of the current tariff transmission rate from the current rate ceiling, without increasing the residual sales price, will force transmission providers to fail to recover their full costs of providing service because the Commission has previously prohibited these rates from including a transmission component (citing *Green Mountain*, 63 FERC ¶ 61,071 at 61,307–08 (1993) and *Cleveland Electric*, 63 FERC ¶ 61,244 at 62,277–78 (1993)).[208]

Union Electric also argues that the Commission should delete the requirement that the utility subtract the corresponding transmission unit charge in its open access tariff from the existing coordination rate ceiling. According to Union Electric, actual bilateral economy sales do not include adders for recovery of transmission costs, but are typically limited to production or generation costs. Union Electric further asserts that the definition of economy energy coordination agreement is so open-ended, it may apply to many types of coordination transactions that are not mere energy economy sales. Union Electric argues that a split-the-savings charge cannot be unbundled in the manner described by the Commission because it is an incorrect assumption that the rate ceiling for every economy energy coordination sales agreement includes a transmission cost component. If Union Electric is required to arbitrarily subtract a transmission charge for its economy sales, it argues that it will be penalized. At a minimum, it argues, a utility should be permitted to submit a list of economy coordination rate schedules that it believes to be already unbundled and should not have to subtract a transmission charge. Alternatively, it argues that the Commission should not require unbundling unless the Commission determines that the existing rate ceiling has been cost justified on a basis that includes an allowance for the full recovery of transmission function cost.[209]

Commission Conclusion

SoCal Edison represents that its package agreements include requirements services as well as coordination services. For existing bilateral economy energy coordination agreements, Order No. 888, as clarified by the Commission's May 17 Order, requires the unbundling of transmission from generation for all such contracts on or before December 31, 1996.[210] Thus, any economy energy service included in existing package agreements must be unbundled.

Regarding non-firm energy sales made under a package agreement, SoCal Edison provides no information distinguishing that service from other

[205] FERC Stats. & Regs. at 31,729; *mimeo* at 277.

[206] FERC Stats. & Regs. at 31,729–30; *mimeo* at 277–78.

[207] Anaheim, in an answer opposing SoCal Edison's request for clarification regarding its package agreements, requests that these agreements be dealt with on a case-by-case basis ''in context.'' (Anaheim Answer). While answers to requests for rehearing generally are not permitted, we will depart from our general rule because of the significant nature of this proceeding and accept the Anaheim Answer.

[208] *See also* VEPCO.

[209] *See also* Florida Power Corp (if the Commission requires an unbundled transmission rate, it must allow transmission providers to reformulate their unbundled economy energy agreements to recover both their capacity and energy costs and the costs of transmission).

[210] FERC Stats. & Regs. at 31,730; *mimeo* at 277.

economy energy coordination transactions, which include all ''if, as and when available'' services (*see* section 35.28(b)(2)). Absent more information, non-firm energy sales should be unbundled.

We further note that our requirements concerning unbundling of bilateral coordination arrangements apply regardless of whether such arrangements are governed by the public interest or just and reasonable standard of review.

With respect to APPA's concerns, the Final Rule provides that all bilateral economy energy coordination contracts executed before the effective date of the Final Rule must be modified to require unbundling of any economy energy transaction occurring after December 31, 1996. Non-economy energy bilateral coordination contracts executed before the effective date of the Final Rule, however, were allowed to continue in effect, but subject to complaints filed under section 206 of the FPA.[211] We drew this distinction for both policy and practical reasons. The ability to use discounts on transmission in order to favor short-term economy energy sales made out of the transmission provider's own generation was of particular concern to the Commission. Thus, in order to eliminate the ability of transmission providers to exercise undue discrimination for short-term coordination transactions under existing umbrella-type agreements, we required unbundling by December 31, 1996.[212] However, non-economy energy coordination agreements presented a different situation.

In the Final Rule, we expressed a particular concern with not abrogating non-economy energy coordination agreements, which we indicated may reflect complementary long-term obligations among the parties.[213] Non-economy energy coordination agreements consist for the most part of long-term reliability arrangements. Providing for the abrogation of these arrangements could cause special problems for the reliable operation of the grid. Examples include agreements governing sales during emergency or maintenance periods. These agreements, unlike economy energy agreements where trade is on an ''as, if and when available'' basis, often have specified terms governing the parties' responsibilities. As a result, many non-economy energy coordination agreements are more akin to requirements contracts than to economy energy coordination agreements. Therefore, we determined to permit this category of contracts to run their course, absent a case specific complaint. The burden would be on the complainant to demonstrate that the transmission component of a non-economy energy coordination agreement is unduly discriminatory or otherwise unlawful. The Commission would decide based on the facts of the case whether unbundling is the appropriate remedy. Neither CCEM nor APPA have presented evidence or convincing arguments as to why these types of agreements should be unbundled generically.[214]

The Commission affirms the requirement in Order No. 888 that the transmission rate for any economy energy coordination service be unbundled. The Commission states in Order No. 888 that to adequately remedy undue discrimination, public utilities must remove preferential transmission access and pricing provisions from agreements governing their transactions.[215] In the cases cited by Utilities For Improved Transition, the Commission prohibited the utility from charging a split-savings rate *plus* a contribution to fixed costs. The Commission has long allowed utilities to set their coordination rates by reference to their own costs (cost-based ceilings) or by dividing the pool of benefits (fuel cost differentials) brought about by the transaction.[216] Utilities have been free to design a rate using either method but not both. Regardless of the method adopted to set a bundled rate on file (a seller's own costs or a sharing of transaction benefits), a bundled rate constitutes the *total charge* for all components and must now be unbundled.

A split-savings rate is set without reference to the seller's fixed costs and, therefore, Union Electric's argument is not germane. We are not requiring that the present rate be adjusted upward or downward. Rather, we are requiring disassembly of the existing rate into component parts one of which represents the rate being charged for transmission service. If a utility is no longer satisfied that an existing rate is compensatory, with regard to either the generation component or the transmission component, it may file an appropriate revision under section 205.

ISO Principles

In the Final Rule, the Commission set out certain principles that will be used in assessing ISO proposals that may be submitted to the Commission in the future.[217] The Commission emphasized that these principles are applicable only to ISOs that would be control area operators, including any ISO established in the restructuring of power pools.

The Commission set forth the following principles for ISOs:

1. The ISO's governance should be structured in a fair and non-discriminatory manner.

2. An ISO and its employees should have no financial interest in the economic performance of any power market participant. An ISO should adopt and enforce strict conflict of interest standards.

3. An ISO should provide open access to the transmission system and all services under its control at non-pancaked rates pursuant to a single, unbundled, grid-wide tariff that applies to all eligible users in a non-discriminatory manner.

4. An ISO should have the primary responsibility in ensuring short-term reliability of grid operations. Its role in this responsibility should be well-defined and comply with applicable standards set by NERC and the regional reliability council.

5. An ISO should have control over the operation of interconnected transmission facilities within its region.

6. An ISO should identify constraints on the system and be able to take operational actions to relieve those constraints within the trading rules established by the governing body. These rules should promote efficient trading.

7. The ISO should have appropriate incentives for efficient management and administration and should procure the services needed for such management and administration in an open competitive market.

8. An ISO's transmission and ancillary services pricing policies should promote the efficient use of and investment in generation, transmission, and consumption. An ISO or an RTG of which the ISO is a member should conduct such studies as may be necessary to identify operational problems or appropriate expansions.

9. An ISO should make transmission system information publicly available on a timely basis via an electronic

[211] FERC Stats. & Regs. at 31,730; *mimeo* at 277.

[212] Approximately 300 filings to unbundle this category were filed by December 31, 1996.

[213] FERC Stats. & Regs. at 31,666; *mimeo* at 90.

[214] Regarding CCEM's request that non-economy energy coordination agreements be identified in determining available transfer capacity (ATC), we note that all data used to calculate ATC and total transfer capacity (TTC) must be made publicly available upon request pursuant to section 37.6(b)(2)(ii) of the OASIS regulations.

[215] FERC Stats. & Regs. at 31,726; *mimeo* at 268–69.

[216] *See e.g.*, Illinois Power Company, 62 FERC ¶ 61,147 at 62,062 (1993).

[217] FERC Stats. & Regs. at 31,730–32; *mimeo* at 279–86.

information network consistent with the Commission's requirements.

10. An ISO should develop mechanisms to coordinate with neighboring control areas.

11. An ISO should establish an alternative dispute resolution (ADR) process to resolve disputes in the first instance.

Rehearing Requests

General Comments

NY Municipal Utilities argue that if the NYPP participants (or other tight pools) elect to establish an ISO, the ISO Principles should be made mandatory for the protection of transmission dependent utilities.

NY Com asks the Commission to clarify that it will allow flexibility to states and utilities in structuring proposals that meet the goals underlying the ISO principles. It explains that the parties to New York's electric competition proceeding are discussing the formation of an ISO in which transmission owners control the system operator, but would have to divest their competitive generation. NY Com further notes that it has not decided that matter yet, but it does not want to see such options foreclosed.

Minnesota P&L argues that certain functions, particularly those involving local area circumstances and safety, are better handled at the local level. It further argues that control area responsibilities of an ISO should focus on regional issues and operations, and on establishing and enforcing uniform criteria and guidelines for local control area operations in order to assure non-discriminatory treatment of all transmission customers.

AMP-Ohio asserts that the Commission should require the separation of transmission, generation and distribution through an ISO and, at a minimum, the Commission should include a Stage 3 of implementation to bring ISOs to reality.

ISO Principle 1

NYPP argues that the Commission should not include a rigid ban on transmission owner leadership in ISO governance because it is the transmission owner that is ultimately responsible for the reliability of the bulk power system.[218]

ISO Principle 2

NYPP asks that the Commission revise this principle to take a more flexible approach to significant employee issues. NYPP explains that it has 81 management employees on the payroll of individual member systems and that pension rights (accrual rights based on an average salary) and medical insurance (preexisting conditions) are through the individual member systems.

ISO Principle 3

SoCal Edison asks that this principle be revised to permit a separate access charge for each utility in order to avoid cost shifting. Anaheim seeks revision of this principle to require that an ISO provide comparable compensation to all transmission owners that make transmission facilities available for use by the ISO.

ISO Principle 5

Anaheim asks that this principle be revised to make clear that ISO arrangements should seek to encourage participation by all transmission owners within the region.

ISO Principle 6

NYPP seeks clarification that an ISO needs control over more than some generation facilities because the more generating facilities operating under an ISO the more reliability there is. Thus, it asserts that the Commission should clarify that its description of ISO control of generation does not require only a minimalist approach to ISO generation control.

ISO Principle 8

SoCal Edison seeks revision of this principle to remove the language linking the ISO to performing studies necessary to identify appropriate grid expansions. According to SoCal Edison, an ISO should not be a project sponsor or should not conduct planning studies to determine what facilities should be constructed because those actions would compromise its independence. In addition, SoCal Edison seeks revision of this principle to permit a transmission usage charge that incorporates locational marginal cost pricing for managing transmission congestion.

Commission Conclusion

We reaffirm our strong commitment to the concept of ISOs, and to the ISO principles described in Order No. 888. We continue to believe that properly structured ISOs can be an effective way to comply with the comparability requirements of open access transmission service. Nevertheless, we do not believe at this time that it is appropriate to require public utilities or power pools to establish ISOs, as suggested by AMP-Ohio. We think it is appropriate to permit some time to confirm whether functional unbundling will remedy undue discrimination before reconsidering our decision that ISO formation should be voluntary.

A number of the above rehearing requests on ISOs are from New York parties and deal with ongoing efforts in New York that would reform the New York Power Pool pooling agreements, restructure power markets, and possibly form an ISO. Some of these arguments are in apparent conflict; for example, the NY Municipal Utilities argue that the 11 ISO principles should be made mandatory if the New York Power Pool participants elect to establish an ISO, while the NY Com argues that the Commission should clarify Order No. 888 to state that it will allow flexibility to states and utilities in structuring proposals that meet the goals underlying the ISO principles. We note that since the time the rehearing requests were filed, the NY Power Pool has filed amendments to its pooling agreements on December 30, 1996 and also has filed, on January 31, 1997, various agreements and tariffs designed to implement an ISO and market exchange. To the extent the rehearing requests from New York parties deal with matters that have been filed with the Commission subsequent to the rehearing requests, the Commission will address the issues raised in the context of those filings.

In response to NY Com's request for clarification that we provide flexibility to states and their utilities in structuring ISO proposals, the Commission at this time clearly cannot, and does not intend to, prescribe a ''cookie cutter'' approach to ISOs. However, the Commission does believe that certain basic principles must be met to ensure non-discriminatory transmission services. We reaffirm our view that ISO Principles 1 (independence with respect to governance) and 2 (independence with respect to financial interests) are fundamental to ensuring that an ISO is truly independent and would not favor any class of transmission users. As the Commission stated in its recent order on the proposed PJM ISO:

> The principle of independence is the bedrock upon which the ISO must be built if stakeholders are to have confidence that it

[218] Sithe, in a response to the NYPP's request for clarification, opposes the ''transmission owners only'' ISO sought by NYPP. (Sithe Response). Subsequently, NYPP filed an objection to Sithe's pleading and request that it be rejected. (NYPP Objection). NYPP explains that its rehearing was a request that the Commission refrain from setting fixed rules for ISO governance in advance, not an argument that the Commission should adopt one particular mechanism or another for all ISOs. While answers to requests for rehearing generally are not permitted, we will depart from our general rule because of the significant nature of this proceeding and accept the Sithe Response and NYPP Objection.

will function in a manner consistent with this Commission's pro-competitive goals.[219]

ISO governance that is disproportionately influenced by transmission owners, unless they have fully divested their interests in generation, is not consistent with ISO Principle 1. We remain concerned that ISO proposals that do not include governance by a fair representation of all system users may not be independent, although we reserve final judgment on any specific governance structure until we have an opportunity to review a specific proposal.[220]

In response to the argument made by NYPP that transmission owner leadership in ISO governance may be needed because transmission owners are ultimately responsible for the reliability of the bulk power system, we emphasize that reliability is of primary importance to this Commission and that the formation and operation of an ISO should not in any way impair reliability. We believe that one of the main purposes of an ISO is to make an independent party, the ISO, responsible for at least short-term reliability. Even if both the transmission owners and the ISO will be responsible for some aspects of reliability, this does not affect our finding that the governance of the ISO must be independent of the transmission owners so that the ISO can carry out its own responsibilities in a not-unduly discriminatory manner.

In response to arguments of the NYPP that the Commission should revise Principle 2 to take a more flexible approach to employee issues, we reaffirm the necessity of requiring the employees of an ISO to be financially independent of market participants and note that Principle 2 suggests that a short transition period should be adequate for ISO employees to sever all financial ties with former transmission owners. We recognize that some flexibility may be necessary regarding the length of a transition period, but believe that ISO employees must in fairly short order be independent of all financial ties to any market participants, if we are to achieve not unduly discriminatory practices in generation and transmission markets.

A number of additional parties seek other revisions to or clarifications of the ISO Principles. For example, Minnesota P&L requests clarification or rehearing to ensure that the Commission provides sufficient flexibility to permit local operators, under the general supervision and control of the ISO, to perform local operational functions, such as performing switching operations. In response to this concern, we note that Principle 3 (open access under a single tariff) says that the portion of the transmission grid operated by a single ISO should be as large as possible. Our view, as described above, is that an ISO, which includes all affected users, should be responsible for operation of the system and ensuring reliability. The ISO may use some combination of actual physical control over facilities and virtual control of facilities by others (*i.e.*, the ISO exercises control over facilities by instructing the transmission owners' or generation owners' staffs as to the actions to be taken). The broad range of interested parties that establish the ISO must determine what services the ISO will perform and what services transmission owners or others will perform under ISO supervision.

We deny the requests by Socal Edison and Anaheim to revise ISO Principle 3 to permit separate access charges for each utility to avoid cost shifting. We think ISO Principle 3 already provides sufficient flexibility to accommodate the concerns of these parties with respect to design of access charges and compensation to owners for transmission facilities under operational control of the ISO.

Similarly, we see no reason to revise Principle 5 (control of interconnected operations) as requested by Anaheim. We agree with Anaheim that wide participation of transmission owners in a region will help ensure open access and increase efficient transmission coordination. ISO Principle 3 says that the portion of the transmission grid operated by a single ISO should be as large as possible. ISO Principle 5 says that an ISO should have control over the operation of interconnected transmission facilities within its region. These principles, as written, address Anaheim's concern.

With respect to NYPP's request for clarification of ISO Principle 6 (dealing with constraints), we note that the description of ISO Principle 6 in the Final Rule says that the ISO may need to exercise some level of operational control over generation facilities in order to regulate and balance the power system.[221] We do not think it is appropriate for the Commission to give further generic guidance now on what constitutes the proper level of operational control over generation. The ISO, including all stakeholders, needs to address this issue, based on the structure of power markets and perhaps other local considerations, in preparing a specific proposal for our approval.

Finally, we deny SoCal Edison's request for revision of ISO Principle 8 (pricing). In response to SoCal Edison's concern, ISO Principle 8 allows the use of appropriate locational marginal cost pricing. The principle allows flexibility regarding which regional organization of market participants (ISO or RTG) conducts the necessary studies to identify the need for expansion. We are unpersuaded by SoCal Edison's arguments that the fact that an ISO is involved in planning for transmission facility expansion would in any way compromise the independence of the ISO.

G. Pro Forma Tariff

In the Final Rule, the Commission combined the requirements for point-to-point transmission service and network transmission service into a single pro forma tariff.[222] The Commission explained that this eliminates many of the differences between the two NOPR pro forma tariffs, provides a unified set of definitions, and consolidates certain common requirements such as the obligation to provide ancillary services. The Commission also noted that it was issuing an accompanying Notice of Proposed Rulemaking in Docket No. RM96–11–000 in which it was seeking comments on whether a different form of open access tariff—one based solely on a capacity reservation system—might better accommodate competitive changes occurring in the industry while ensuring that all wholesale transmission service is provided in a fair and non-discriminatory manner.[223]

1. Tariff Provisions That Affect The Pricing Mechanism

a. Non-Price Terms and Conditions

In the Final Rule, the Commission explained that the Final Rule pro forma tariff is intended to *initiate* open access, with non-price terms and conditions based on the contract path model of power flows and embedded cost ratemaking.[224] It emphasized that the Final Rule pro forma tariff is not intended to signal a preference for contract path/embedded cost pricing for the future. The Commission indicated

[219] Atlantic City Electric Company, *et al.*, 77 FERC ¶ 61,148 (1996) (*mimeo* at 36–41); *see also* Pacific Gas & Electric Company, 77 FERC ¶ 61,204 (1996).

[220] In making this finding, we are not suggesting that an independent transmission company, which owns only transmission, is undesirable. However, an ISO, which separates ownership and operation, is designed in large part to recognize that transmission owners today have significant generation or load interests that may bias their operational decisions.

[221] FERC Stats. & Regs. at 31,731; *mimeo* at 283.

[222] FERC Stats. & Regs. at 31,733; *mimeo* at 288–89.

[223] FERC Stats. & Regs. at 31,733; *mimeo* at 289.

[224] FERC Stats. & Regs. at 31,734–35; *mimeo* at 291–93.

that it will in the future entertain non-discriminatory tariff innovations to accommodate new pricing proposals.

The Commission further indicated that, by initially requiring a standardized tariff, it intends to foster broad access across multiple systems under standardized terms and conditions. However, the Commission emphasized that the tariff provides for certain deviations where it can be demonstrated that unique practices in a geographic region require modifications to the Final Rule pro forma tariff provisions.

Finally, the Commission stated that it will allow utilities to propose a single cost allocation method for network and point-to-point transmission services.

b. Network and Point-to-Point Customers' Uses of the System (so called ''Headroom'')

In the Final Rule, the Commission explained that it will not allow network customers to make off-system sales within the load-ratio transmission entitlement at no additional charge.[225] The Commission further explained that use of transmission by network customers for non-firm economy purchases, which are used to displace designated network resources, must be accorded a higher priority than non-firm point-to-point service and secondary point-to-point service under the tariff. In addition, the Commission found that off-system sales transactions, which are sales other than those to serve the transmission provider's native load or a network customer's load, must be made using point-to-point service on either a firm or non-firm basis. In rejecting the ''headroom'' concept (where a network customer can make off-system sales as long as its total use of the system does not exceed its coincident peak demand), the Commission explained that it was not requiring any utility to take network service to integrate resources and loads and if any transmission user (including the public utility) prefers to take flexible point-to-point service,[226] they are free to do so. Further, the Commission explained that any point-to-point customer may take advantage of the secondary, non-firm flexibility provided under point-to-point service equally, on an as-available basis.

Rehearing Requests

A number of entities argue that it is unreasonable to permit firm point-to-point customers to receive non-firm service, up to their contract demand, at no additional charge, at secondary receipt and delivery points, but to require transmission providers and network customers to purchase transmission for all off-system sales, including non-firm sales made in competition with sales made by the point-to-point customer.[227] FPL asserts that having built and paid for the entire transmission network, the owner and the network customer should have the flexibility to use the network as they need. Utilities For Improved Transition declare that just as the firm point-to-point customer is permitted to maximize the use of its contract demand, the transmission provider and network customer should be entitled to maximize their long-term fixed cost obligation (citing *AES Power, Inc.*, 69 FERC ¶ 61,345 at 62,300 (1994) (*AES*) for the proposition that the utility and its native load customers are obligated to pay all the costs of the transmission system without regard to the amount of energy actually scheduled).

FPL and Carolina P&L suggest two possible solutions: (1) allow the transmission provider and network customer to have rights to the headroom beneath their fixed cost obligations at no additional charge, or (2) restrict the no-charge use of firm point-to-point headroom to transmission service associated with non-firm purchases to serve load. Under either of these options, they assert, the firm point-to-point customer's rights to make non-firm off-system sales would be on an even competitive footing with the transmission provider or network customer.

PA Coops maintain that network customers should have the right to reassign/sell unused capacity below their 12-month rolling average peak demand at no additional charge. Cajun argues that network customers should be allowed to use the transmission system for non-firm (and perhaps firm) coordination transactions at no additional cost, provided the network customer's total use of the transmission system does not exceed its load ratio share. Cajun notes that the Commission seems to have determined elsewhere in the Rule that a network customer has already paid for the full use of its load ratio share (citing *mimeo* at 332 and 338). In addition, Cajun states that requiring the network customer to use point-to-point service results in the network customer paying twice for the same capacity.

VT DPS argues that the Commission should permit network users to make limited use of their network capacity to make off-peak off-system sales. It asserts that UtiliCorp's network tariff, filed in Docket No. ER95–203, provides a useful model: ''the level of capacity utilized by the company or the customer for its combined network load and off-system sales load would be fixed by the tariff as the highest coincident peak load experienced by the transmitting utility in the three years preceding the off-system sale.'' According to VT DPS, this places all firm users on a par. In contrast, VT DPS argues that the Commission's solution is arbitrary and patently inadequate. VT DPS claims that concerned parties are not just transmission providers, but include state agencies and entities that need to take network service. VT DPS further argues that the lower priority for secondary service under the point-to-point tariff may pose an unacceptable risk to public utilities with firm obligations to serve their load, and having to agree to a fixed demand quantity may be unsatisfactory for public utilities with growing customer loads and a statutory obligation to serve those loads.

LEPA argues that:

> [t]he Commission erred in not finding that in order to compete, one must be able to utilize base load units of 500MW size because entry without the ability to employ such base load units would make the putative entrant unable to compete; that in order to employ such units, or portions of them, the entrant had to engage in the coordinated development of base load units; that such coordinated development requires use of transmission for that purpose so as to be able to sell portions of the output of a baseload unit off-system, and that without 'headroom,' the cost of transmission for that purpose would not be comparable with the cost of transmission for the same purpose of the owner of the transmission. (LEPA at 5).

Commission Conclusion

The requests for rehearing on this issue present no arguments that were not fully considered in Order No. 888. Petitioners continue to claim that transmission providers and network customers are competitively disadvantaged vis-a-vis point-to-point transmission customers due to the point-to-point customers' ability to use as available, non-firm service over secondary points of receipt and delivery at no additional cost. The Commission attempted to strike a balance on this issue in Order No. 888 by allowing both network and point-to-point services to be priced on the same basis (*i.e.*, no longer summarily rejecting the use of the average of the 12 monthly system

[225] FERC Stats. & Regs. at 31,751; *mimeo* at 342–43.

[226] *See* Florida Municipal Power Agency v. Florida Power & Light Company, 74 FERC ¶ 61,006 at 61,013 and n.70 (1996).

[227] *E.g.*, FPL, Utilities For Improved Transition, TDU Systems, Carolina P&L, AEC & SMEPA, VT DPS, EEI.

peaks as the denominator for the rate for point-to-point service). Additionally, the Commission established a lower priority for the non-firm secondary point-to-point service than for either economy purchases by network customers or for stand-alone non-firm point-to-point service, as discussed in Section IV.G.3.b. Accordingly, we believe that these concerns have been sufficiently addressed.

Furthermore, these entities want to be allowed to make off-system sales under their network service at no additional charge as long as their total use of the system does not exceed their load ratio share. They claim that it is inequitable not to allow such ''headroom'' sales under the network service while allowing firm point-to-point customers to use non-firm transmission service up to their contract demands using secondary receipt and delivery points at no additional charge. As the Commission stated in Order No. 888, customers are not obligated to take network transmission service.[228] If customers want to take advantage of the as-available, non-firm service over secondary points of receipt and delivery through the point-to-point service, they may elect to take firm point-to-point transmission service in lieu of the network service. We further note that transmission providers must take point-to-point transmission service for their own off-system sales, which results in comparable treatment for both the transmission provider and network customers. Transmission providers and other customers taking point-to-point transmission service do not need to be allowed to make ''headroom'' sales because they have access to as-available, non-firm service over secondary points of receipt and delivery at no additional charge through their point-to-point service.

Cajun's argument that a network customer has already paid for the full use of its load-ratio share of the system ignores the fact that network service is based on integrating a network customer's resources with its load, not on making off-system sales. This is why network customers pay for service on a load-ratio basis. If Cajun is concerned that it may need to pay for both network service and point-to-point service, Cajun can simply elect to take point-to-point service for all of its transmission needs.

VT DPS' claim that the lower priority accorded to transmission service to secondary points of receipt and delivery under flexible point-to-point service would present an ''unacceptable risk'' to public utilities is unsubstantiated. If the risk of having this secondary service curtailed is too great, this customer has the option to: (1) take stand-alone non-firm point-to-point service (which has a higher priority), (2) take this service on a firm point-to-point basis, or (3) take network service, which has a higher priority for economy purchases than either stand-alone non-firm or secondary non-firm point-to-point service.

With respect to LEPA's argument, the Commission has the goal of encouraging competition in the generation market, not discouraging generation competition by erecting barriers to entry such as arbitrary generator size. Furthermore, LEPA's argument that comparability is not achieved without allowing headroom is incorrect because both network customers as well as the transmission provider must obtain point-to-point transmission service to accommodate transmission for wholesale sales.

c. Load Ratio Sharing Allocation Mechanism for Network Service

In the Final Rule, the Commission concluded that the load ratio allocation method of pricing network service continues to be reasonable for purposes of initiating open access transmission.[229] The Commission also reaffirmed the use of a twelve monthly coincident peak (12 CP) allocation method because it believed the majority of utilities plan their systems to meet their twelve monthly peaks. However, the Commission stated that it would allow utilities to file another method (*e.g.*, annual system peak) if they demonstrate that it reflects their transmission system planning.

With respect to concerns raised about pancaked rates for network service provided to load served by more than one network service provider, the Commission indicated that if a customer wishes to 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, it may do so. However, customers that elect to do so, the Commission explained, must seek alternative transmission service for any such load that has not been designated as network load for network service. The Commission indicated that this option is also available to customers with load served by ''behind the meter'' generation [230] that seek to eliminate the load from their network load ratio calculation.

(1) Multiple Control Area Network Customers

Rehearing Requests

A number of entities argue that excluding load from the designation of Network Load does not solve the pancaking problem and results in the network customer paying even more transmission charges. They contend that a network customer must still pay two network charges and point-to-point charges to be able to operate its resources across two control areas. The Commission's approach, they argue, makes it impossible for a network customer with loads and resources in multiple control areas to integrate those loads and resources on an economic dispatch basis.[231] In essence, these entities state that a network customer must frequently dispatch resources in one transmission provider's control area (control area A) to serve that customer's load (in the case of a G&T cooperative, the load of a member system or third-party requirements customer) located in an adjacent control area of another transmission provider (control area B). As a result, they believe, the tariff essentially requires that network load in control area B, served by resources in control area A, must be counted as load in control area B. Alternatively, they believe that the tariff allows the transmission of resources in control area A to load in control area B as point-to-point transmission that requires an additional charge. These entities argue that either of these situations produces uneconomic results for multiple control-area network customers.

To avoid these problems, these entities propose that a network customer be allowed to use its network service to transmit power and energy from resources in control area A to serve load in control area B without designating the control area B load as network load for billing purposes. These entities suggest that no additional compensation should be required if such transfers to load in adjacent control areas plus other network transactions on behalf of the transmission customer in control area A do not exceed the customer's coincident demand in control area A. They also maintain that the ultimate solution is a regional system operated by an ISO. At the very least, TDU Systems contends, the Commission should require provision of service to network customers with loads and resources

[228] FERC Stats. & Regs. at 31,751; *mimeo* at 342–43.

[229] FERC Stats. & Regs. at 31,736; *mimeo* at 296–97.

[230] Behind-the-meter generation means generation located on the customer's side of the point of delivery.

[231] *E.g.*, NRECA, TDU Systems, Blue Ridge.

located on multiple systems under a rate that recovers the customer's load ratio share—but no more—of the transmission owners' collective transmission investment in the control areas that the customer straddles.

AMP-Ohio maintains that rational economic transmission pricing policies demand elimination of the pancaking of rates caused by the arbitrary ownership boundaries of individual utilities.

TAPS asks that the Commission clarify that the Commission will look closely at how to create and promote region-wide rates when evaluating mergers and market-based rate proposals. It argues that the Commission should be receptive to section 211 filings seeking non-pancaked rates and should establish a Stage 3 for the purpose of addressing directly the need for transmission access on a non-pancaked, regional basis.

Commission Conclusion

In the Final Rule, the Commission addressed concerns regarding pancaked rates for network service for customers with load in multiple control areas.[232] Tariff section 31.3 allows a network customer the option to exclude all load from its designated network load that is outside the transmission provider's transmission system, and to serve such load using point-to-point transmission service.

NRECA and TDU Systems, however, argue that network customers located in multiple control areas should not have to pay for any additional point-to-point transmission service to make sales to non-designated load located in a separate control area. We disagree. Because the additional transmission service to non-designated network load outside of the transmission provider's control area is a service for which the transmission provider must separately plan and operate its system beyond what is required to provide service to the customer's designated network load, it is appropriate to have an additional charge associated with the additional service.

AMP-Ohio's concerns regarding ''arbitrary ownership boundaries of individual utilities,'' and TAP's proposal to require regional rates are beyond the scope of Order No. 888.[233] However, as the Commission explained in the Final Rule, it encourages the voluntary formation of regional transmission groups, as well as the establishment of regional ISOs, and will address those matters on a case-by-case basis.

(2) Twelve Monthly Coincident Peak v. Annual System Peak

Rehearing Requests

Several utilities ask that the Commission eliminate the requirement that charges for network service be calculated using a 12-month rolling average load ratio share and allow utilities discretion to determine the way network customers pay.[234] They assert that the requirement makes it impossible to recover the full cost of service when customers begin or terminate service. They suggest a unit charge based on a formula rate that is trued up each year or a month-by-month load ratio share calculation.

NE Public Power District states that the definition of load ratio share in section 1.16 of the pro forma tariff, taken together with sections 34.2 and 34.3 of the pro forma tariff require the use of the 12–CP method and the inclusion of losses to the generator bus. This, it argues, is inconsistent with the Commission's statement that ''[u]tilities that plan their systems to meet an annual system peak * * * are free to file another method if they demonstrate that it reflects their transmission system planning.'' (NE Public Power District at 22–23). NE Public Power District argues that utilities should be allowed to use CP demands measured at delivery points at some common specified voltage. It further asks the Commission to clarify whether the monthly peak includes or excludes transmission losses.

EEI and AEP argue that transmission reservations for services of less than one month's duration and any discounted firm transactions should not be counted in the load ratio calculation when determining the 12 CP on point-to-point rates, but that the revenues from these services should be credited to all firm transmission users.

Montana Power argues that the Commission's pricing approach discriminates against native load customers because all non-network uses of the system do not occur at full, non-discounted prices for the entire month and the effects of discounts will be shouldered by native load customers. According to Montana Power, this is a disincentive to utilities to offer discounts and creates a possibility of gaming by network customers buying one day firm point-to-point reservations to reduce their network load ratio shares.

Commission Conclusion

While the Commission reaffirmed the use of a twelve monthly coincident peak (12 CP) allocation method for pricing network service in the Final Rule, the Commission also stated:

> [u]tilities that plan their systems to meet an annual system peak * * * are free to file another method if they demonstrate that it reflects their transmission system planning.[235]

Accordingly, utilities are free to propose in a section 205 filing an alternative to the use of the 12-month rolling average (e.g., annual system peak) in the load ratio share calculation, subject to demonstrating that such alternative is consistent with the utility's transmission system planning and would not result in overcollection of the utility's revenue requirement. Any proposed alternative would also be subject to any future filing conditions established by the Commission.[236]

We also are not convinced that we should require the calculation of load ratios using a particular method on a generic basis. Any such proposals, including those concerning the treatment of discounted firm transmission transactions in the load ratio calculation and revenue credits associated with such transactions, are best resolved on a fact-specific, case-by-case basis.

Finally, the Final Rule does not prohibit utilities from ''us[ing] CP demands measured at delivery points at some common specified voltage'' as claimed by NE Public Power District. Treatment of transmission losses can be accomplished in different ways by different transmission providers under the pro forma tariff, such as adjustment to a consistently applied voltage level.

Regarding NE Public Power District's allegation that certain sections of the pro forma tariff do not allow the use of the annual system peak method in the load ratio share calculation, the Commission recognizes that certain rate methodologies may require minor adjustments to the non-price terms and conditions to be consistent with the proposed rate methodology. However, any modifications to the non-price terms and conditions established in the pro forma tariff must be fully supported by the utility and the appropriateness of such proposed changes will be evaluated by the Commission for

[232] FERC Stats. & Regs. at 31,736; *mimeo* at 297.

[233] These entities do not explain how the Commission could force non-public utility control area operators, of which there are approximately 62 out of 138 in the United States (as of October 1996), to accede to these pricing policies.

[234] *E.g.*, Utilities For Improved Transition, Florida Power Corp, VEPCO.

[235] FERC Stats. & Regs. at 31,736; *mimeo* at 296–97.

[236] FERC Stats. & Regs. at 31,770; *mimeo* at 398–99.

consistency with the proposed rates or rate methodologies. The remainder of NE Public Power District's concerns are case-specific and should be raised by NE Public Power District at such time as a transmission provider makes a filing.

(3) Load and Generation ''Behind the Meter''

Rehearing Requests

Several entities request clarification[237] concerning the definition of Network Load in pro forma tariff section 1.22, which provides, in pertinent part, that:

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.

These entities maintain that section 1.22 is too restrictive and is inconsistent with the Final Rule's treatment of load served from ''behind the meter'' generation.[238] Specifically, these entities request that the Commission clarify that a network customer can exclude from its designated network load a portion of load at a discrete point of delivery, which is served from generation behind the meter. In support of this position, a number of petitioners cite to *FMPA* v. *FPL*, 74 FERC ¶ 61,006 at 61,012–13, in which they claim the Commission allowed network customers to exclude load served by behind the meter generation.[239]

TAPS asserts that there is no operational or economic reason to require the designation of all load at a discrete point of delivery as network load.

FMPA argues that network customers should not be charged a network rate to use their own transmission (or distribution) system to serve loads that are located beyond the transmission owner's system. FMPA interprets the Final Rule on this issue as allowing a network customer that has behind-the-meter generation to serve part of its behind the meter load from such generation; thus, a customer can exclude that load, which is served without using the transmission provider's transmission system, from the load ratio share. FMPA's interpretation of section 1.22 is that ''a network customer may not import power using both point-to-point and network transmission service at the same delivery point, but that this Section does not prevent a network customer from serving load from generation when both are behind the delivery point and when the transaction does not rely upon use of the transmission provider's transmission system.'' (FMPA at 5). FMPA requests that the Commission clarify the language in section 1.22 consistent with its interpretation above.

Michigan Systems asks the Commission to modify section 1.22 because the ''clause may be interpreted to require network integration transmission service customers to pay a second time for the transmission of power that is already being transmitted under other arrangements, such as transmission ownership. The clause could also be interpreted to allow the transmission provider to charge customers for the transmission of power which does not use the transmitter's system, such as for transmission from 'behind the meter' generation to 'behind the meter' load.'' (Michigan Systems at 5–13).

Wisconsin Municipals ask the Commission to ''clarify that a partial designation is appropriate if (1) only part of the load behind a particular delivery point relies upon the transmission provider's transmission system for service or (2) a network customer is responsible for serving only a portion of the load behind a discrete delivery point.'' (Wisconsin Municipals at 17–18).

Blue Ridge asks the Commission to clarify that it intended to allow for multiple ownership of resources by customers who are not network customers.

Utility Position

FPL and Carolina P&L ask the Commission to clarify that section 1.22 and the Rule (*see also* Original Sheet No. 94 and *FMPA I*, 67 FERC ¶ 61,167 at 61,481–82 (1994)) mean that regardless of whether or not a customer has behind the meter or local generation at a delivery point, if a customer wants to purchase network service to serve load at a delivery point, it must purchase network service for all such load—the customer cannot split the load into network and point-to-point components at a specific point of delivery.[240] Otherwise, FPL states, there would be a split system with the potential to game the system and problems with how it would work.

AEP argues that the option in section 1.22 of excluding load from network load should be deleted. AEP states that, as the Commission recognized in its original *FMPA* v. *FPL* order, the provision is contrary to the comparability standard. Specifically, AEP argues that transmission-owning utilities do not and cannot offer themselves partial integration service electing to pay only a portion of the network costs, but rather must pay for the entire network, which integrates all of the transmission-owning utility's resources and loads. According to AEP, the load served by behind-the-meter generation is not isolated from the system, which is there to serve that load when the behind-the-meter generation is unavailable. Allowing a network customer to use short-term non-firm point-to-point transmission, AEP asserts, allows customers to evade a large portion of the network's costs, which they will do on an unconstrained system such as AEP.

Commission Conclusion

We disagree that the prohibition in tariff section 1.22 against a network customer designating only part of a load at a discrete point of delivery as network load is either inconsistent with the Final Rule's treatment of generation ''behind the meter'' or is contrary to the Commission's decisions in *FMPA I* and *FMPA II*.

The Commission addressed ''behind the meter'' generation in the Final Rule as follows:

if a customer wishes to 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, it may do so. [citing *Florida Municipal Power Agency* v. *Florida Power & Light Company*, 74 FERC ¶ 61,006 (1996), *reh'g pending*.] Customers that elect to do so, however, must seek alternative transmission service for any such load that has not been designated as network load for network service. This option is also available to customers with load served by 'behind the meter' generation that seek to eliminate the load from their network load ratio calculation.[241]

Implicit in the Commission's discussion of this issue in the Final Rule and also in *FMPA I* and *FMPA II*, in permitting

[237] *E.g.*, AMP-Ohio, TAPS.

[238] *See* FERC Stats. & Regs. at 31,736 and 31,743; mimeo at 297 and 317.

[239] *E.g.*, TAPS, Central Minnesota Municipal.

[240] Utilities For Improved Transition argues that a transmission dependent utility should be required to serve its load using only network transmission service. It asserts that such a utility should not be allowed to avoid its full cost responsibility by using point-to-point firm during peak periods and non-firm service during non-peak periods. *See also* VEPCO.

Moreover, FMPA filed an answer in opposition to the requests for clarification of FP&L, Carolina P&L and others concerning the definition of network load and related issues. (FMPA Answer). Likewise, Michigan Systems and TAPS filed answers opposing these requests for rehearing. (Michigan Systems Answer and TAPS Answer). While answers to requests for rehearing generally are not permitted, we will depart from our general rule because of the significant nature of this proceeding and accept the FMPA Answer, Michigan Systems Answer and TAPS Answer.

[241] FERC Stats. & Regs. at 31,736; *mimeo* at 297.

the ''exclusion of a particular load,'' is that the Commission will allow a network customer to exclude the *entirety* of a discrete load from network load, but not just a portion of the load served by generation behind the meter.

In its request for rehearing of *FMPA I*, FMPA requested that the Commission confirm its interpretation of the Commission's finding in *FMPA I* that:

[FMPA] can choose to serve an *amount* of load in a city from generation in the city, so long as FMPA does not sometimes serve that level of load from external generation or use that generation to serve member loads outside the city.[242]

On rehearing in FMPA II, the Commission did not grant FMPA's request to allow a partial designation of network load. Furthermore, the Commission provided an example of how FMPA could request that certain of its loads and resources be excluded from network integration transmission service. The Commission explained that FMPA could choose to exclude the loads of the cities of Ft. Pierce and Vero Beach from the request for network integrated transmission service and alternatively request point-to-point transmission service to transmit power from resources in those cities to other FMPA members or from FMPA member cities to Ft. Pierce and Vero Beach.[243] The Commission neither stated that it would allow a partial designation of a discrete load as network load nor provided any examples of such treatment.

Additionally, throughout the pro forma tariff, network customers are consistently prohibited from designating only a portion of a discrete network load. For example, tariff section 31.2 provides:

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. [Emphasis added]

Accordingly, we find that no inconsistency exists between the tariff language and either the language in the Final Rule or the Commission's findings in *FMPA I* or *FMPA II*.

In support of its position to allow a partial designation of network load at a point of delivery, TAPS claims that there are no operational reasons to require the designation of all load at a discrete point of delivery as network load. We disagree. Utilities, both commenting on the NOPR and on rehearing (*e.g.*, AEP rehearing at 19–20 and Florida Power & Light at 14–18), express concern that customers allowed to divide a discrete load between point-to-point and network services would create a ''split system.'' The concept of allowing a ''split system'' or splitting a discrete load is antithetical to the concept of network service. A request for network service is a request for the *integration* of a customer's resources and loads. Quite simply, a load at a discrete point of delivery cannot be partially integrated—it is either fully integrated or not integrated. Furthermore, such a split system creates the potential for a customer to ''game the system'' thereby evading some or all of its load-ratio cost responsibility for network services.[244]

For example, FMPA asserts that if a FMPA member city has a peak load of 100 MW and behind the meter generation of 75 MW, FMPA should be allowed to designate a portion of its load as network load (*e.g.*, 60 MW), and to serve the remaining load (*e.g.*, 40 MW) from its behind-the-meter generation.[245] However, as a number of utilities note, this would lead to the possibility of gaming the system. For example, if at the time of the monthly system peak the FMPA member city generates more than 40 MW (or takes short-term firm transmission service (or a combination of the two)), it may be able to lower its monthly coincident peak load for network billing purposes,[246] and thereby reducing if not eliminating its load-ratio cost responsibility for network service. Because network and native load customers bear any residual system costs on a load-ratio basis, any cost responsibility evaded by a network customer in this manner would be borne by the remaining network customers and native load.

FPL also raises several fundamental operational problems associated with allowing partial network service or creating a ''split system:''

If all the loads are included in a single control area, how does the transmission provider know what portion of the power delivered is serving the point-to-point load (which presumably would not be counted toward the network's load ratio)?

Using the same 100 MW load example previously mentioned where there is a 40/60 network/point-to-point split, there would have to be a determination of how the split would be done in non-peak situations. Are the first 40 MW of load all network load, or all point-to-point load, or split on a 40/60 basis?

If the system purchases economy power from non-local resources, how is that delivery allocated between the network portion (for which there would be no point-to-point scheduling, curtailment, or transmission charges) and the point-to-point portion (which must be arranged and paid for separately under a point-to-point tariff)?

The bottom line is that all potential transmission customers, including those with generation behind the meter, must choose between network integration transmission service or point-to-point transmission service. Each of these services has its own advantages and risks.[247]

In choosing between network and point-to-point transmission services, the potential customer must assess the degree of risk that it is willing to accept associated with the availability of firm transmission capacity. Customers choosing point-to-point service, based solely on the amount of transmission capacity reserved (or contract demand), may face a relatively higher risk associated with the availability of firm transmission capacity. For example, if a customer with a peak load of 100 MW, and behind the meter generation of 75 MW, chooses to serve a portion of its load with point-to-point transmission service (*e.g.*, 60 MW) and the remaining load (*e.g.*, 40 MW) with its behind-the-meter generation, this customer faces the risk that, should its generation behind the meter become unavailable, the transmission provider may not have firm transmission capacity available to serve the remaining 40 MW of that

[242] *FMPA II* at 61,012 (emphasis added).

[243] *FMPA II* at 61,011.

[244] The load-ratio cost responsibility is based on the network customer's monthly contribution to the transmission system peak (*i.e.*, coincident peak billing).

[245] FMPA at 3–4.

[246] While this customer could lower its coincident peak use of the transmission system, it could be making substantial use of the transmission system during all other hours of the month but yet have little or no load-ratio cost responsibility.

[247] Customers taking network integration transmission service choose to have the transmission provider integrate their generation resources with their loads. Network service is a service comparable to the service that the transmission provider provides to its retail native load, where the Transmission Provider includes the network customers resources and loads (projected over a minimum ten-year period) into its long-term planning horizon. Because network service is usage based, network customers pay on the basis of their total load, paying a load-ratio share of the costs of the transmission provider's transmission system on an ongoing basis. In contrast, point-to-point transmission service is more transitory in nature. Point-to-point service is frequently tailored for discrete transactions for various time periods, which may or may not enter into the transmission provider's planning horizon. A point-to-point transmission service customer is only responsible for paying for its reserved capacity on a contract demand basis over the contract term.

customer's load. One way to minimize this risk would be for the customer to reserve and pay for additional firm point-to-point transmission service to protect against the unavailability of its behind-the-meter generation. Alternatively, the customer could choose network service in which the transmission provider will plan and provide for firm transmission capacity sufficient to meet the customer's current and projected peak loads, including integration of the customer's behind-the-meter generation as a network resource.

For the reasons stated above, a network customer will not be permitted to take a combination of both network and point-to-point transmission services under the pro forma tariff to serve the same discrete load. Accordingly, the requests for rehearing to modify tariff section 1.22 are hereby rejected.

Moreover, the Commission will allow a network customer to either designate all of a discrete load [248] 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.[249]

(4) Existing Transmission Arrangements associated with Generating Capacity Entitlements (*e.g.*, ''preference power'' customers of PMAs)

Rehearing Requests

Several entities argue that section 1.22 of the pro forma tariff is arbitrary and cannot be reconciled with the Final Rule's determination not to abrogate existing agreements. [250]

Specifically, several transmission customers claim that the prohibition against designating only part of the load at a discrete point of delivery is problematic for customers with existing transmission arrangements for receiving preference power or capacity entitlements from power marketing agencies (PMAs). For example, Central Minnesota Municipal argues that the limiting language of section 1.22 should be eliminated as it would preclude Mountain Lake (a member of Central Minnesota Municipal) from using network transmission and, at the same time, point-to-point transmission for WAPA power under a separate arrangement. These transmission customers assert that if they designate all of the load at a discrete point of delivery as network load, and pay for such network load on a load-ratio basis, then the transmission provider is paid twice for the same transmission service—once through the existing transmission arrangement and a second time through the network service.

NRECA and TDU Systems argue that if a customer chooses to use network service under the pro forma tariff to supplement its existing arrangements to meet future full requirements, the Commission should amend section 1.22 so the transmission provider cannot overcharge the customer:

> A Network Customer may elect to designate less than its total load as Network Load. Where a Network Customer has elected not to designate a particular load as a Network Load, the Network 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, unless such non-designated load is served pursuant to other arrangements. [251]

Alternatively, the transmission customer may choose not to designate any load at a discrete point of delivery as network load. However, these transmission customers note that the preference power allotments received from PMAs typically do not equal the total load of a customer at a discrete point of delivery. Therefore, the customer would need to acquire additional point-to-point transmission service for any remaining transmission needs. Accordingly, these transmission customers conclude that the existence of their current transmission arrangements precludes them from receiving network service which they claim does not allow the comparable use of the system that the transmission provider enjoys.

Commission Conclusion

The Commission recognizes that existing power and transmission arrangements represent a transitional problem as customers begin to take service under the pro forma tariff. Clearly, the Commission did not intend for a transmission provider to receive two payments for providing service to the same portion of a transmission customer's load. Any such double recovery is unacceptable and inconsistent with cost causation principles. Neither did the Commission intend to allow a transmission customer to designate less than its total load as network load at a discrete point of delivery even though a portion of that load is served under a pre-existing contract. We clarify that such a transmission customer has several alternatives it can pursue using either point-to-point or network transmission service.

Using network transmission service, the network customer would designate its existing generation supply contract(s) as a network resource(s) and the associated load served under such contract(s) designated as network load. The network customer then has two options: pursue negotiations with the transmission provider to obtain a credit on its network service bill for any separate transmission arrangements or for the unbundled transmission rate component of the existing generation supply contract or (2) seek to have any separate transmission or the unbundled transmission rate component of its generation supply contract eliminated in recognition of the network transmission service now being provided and paid for under the tariff.[252]

Using point-to-point transmission service, the transmission customer would identify the discrete points of delivery being served under existing generation supply and existing transmission contracts and acquire additional point-to-point transmission service under the tariff for any remaining load at those discrete points of delivery.

Any of these three alternatives should address concerns regarding the possibility of double recovery. Furthermore, a transmission customer may file a complaint under section 206 with the Commission to address any claims of double recovery that it is unable to resolve with the transmission provider.

d. Annual System Peak Pricing for Flexible Point-to-Point Service

In the Final Rule, the Commission indicated that it will allow a transmission provider to propose a formula rate that assigns costs

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[248] We also clarify that while the tariff prohibits the designation of only part of the load at a discrete point of delivery, this prohibition also applies to network customers with a discrete load served by multiple points of delivery. In other words, for the same reasons explained above, a customer may not choose to have part of a discrete load served under network integration service at one or more delivery points and at the same time have the remaining portion of the same load served under point-to-point transmission service at other delivery points.

[249] An example of excluding the entirety of a discrete load would be a municipal power agency excluding the entire load of a member city with generation behind the meter, while requesting network service to serve the remaining member cities' loads. The excluded load of the member city must be met using a combination of generation behind the meter and any remote generation that may be necessary. The member city would be responsible for arranging any point-to-point transmission service under the pro forma tariff that may be necessary to import the power and energy from any remote generation.

[250] *E.g.*, NRECA, TDU Systems, AEC & SMEPA.

[251] NRECA at 78–79; TDU Systems at 32.

[252] Clearly, any such modification of existing contracts would required the agreement of all parties and a filing with the Commission.

consistently to firm point-to-point and network services.[253] The Commission added that it will no longer summarily reject a firm point-to-point transmission rate developed by using the average of the 12 monthly system peaks.

The Commission explained that it still believed that it was appropriate for utilities to use a customer-specific allocated cost of service to account for diversity, but based on the changed circumstances since *Southern Company Services, Inc.*, 61 FERC ¶ 61,339 (1992) (*Southern*), it indicated that it would now permit an alternative. Thus, the Commission indicated that it will allow all firm transmission rates, including those for flexible point-to-point service, to be based on adjusted system monthly peak loads.

In order to prevent over-recovery of costs for those who use this approach, the Commission explained that it will require transmission providers to include firm point-to-point capacity reservations in the derivation of their load ratio calculations for billings under network service. In addition, the Commission explained that revenue from non-firm transmission services should continue to be reflected as a revenue credit in the derivation of firm transmission tariff rates. The Commission noted that the combination of allocating costs to firm point-to-point service and the use of a revenue credit for non-firm transmission service will satisfy the requirements of a conforming rate proposal enunciated in our Transmission Pricing Policy Statement.[254]

Rehearing Requests

Blue Ridge maintains:

> The sea change in the Commission's approach to the pricing of transmission services is not warranted by any claimed change in circumstances and Blue Ridge accordingly requests rehearing and rejection of the new approach. At a minimum, the Commission should clarify that any deviation from use of an annual peak divisor (or other methodology based on system capability) for setting point-to-point transmission rates will be considered only on a case-by-case basis.

TAPS also argues that the use of the same denominator for two different services is inconsistent, unjust and discriminatory. It asserts that the Commission should use a system capability divisor for allocating fixed costs between reservation-based and load-based firm service.

TAPS also asserts that most utilities plan their transmission systems to cover the annual system peak estimated conservatively on the higher side in order to meet unusually high loads reliably, rather than planning on the basis of the twelve monthly peaks as stated in Order No. 888. Therefore, TAPS asks that the Commission maintain 1 CP pricing for point-to-point service. TAPS argues that the Commission should allow transmission providers and customers to demonstrate the appropriate measure for each transmission system's capability in utility-specific proceedings.

If the Commission uses a 12 CP denominator, TAPS requests that the Commission clarify that capacity reservations should be established consistently with that denominator and should recognize the inappropriateness of using such rates as a cap for non-firm rates. It asserts that non-firm rates should be limited to actual variable costs of transmission, plus losses, plus a modest adder as a contribution toward fixed costs. At the very least, TAPS argues that the cap should be developed using a more appropriate denominator, *e.g.*, system capability.

TAPS further argues that if the rate divisor is based on experienced 12 CP, the capacity reservations and the divisor should be measured at the delivery points (as it is for native load customers), not the higher of the receipt or delivery points, to avoid a mismatch between the rate divisor and billing determinants.[255]

Wisconsin Municipals and TAPS argue that if a 12 CP divisor is used, customers must have the flexibility to vary their monthly nomination under the point-to-point tariff.

Commission Conclusion

With respect to TAPS argument that the annual system peak method would be appropriate for most systems, the Commission has determined in Order No. 888 that this issue is best resolved on a case-by-case basis and specifically provided utilities the opportunity to propose to use other allocation methods, including the annual system peak method sought by TAPS.[256]

The Commission already recognized the potential for a mismatch between the rate divisor and billing determinants that TAPS now raises on rehearing. We explicitly stated in the Final Rule that

> [t]he adjusted system monthly peak loads consist of the transmission provider's total monthly firm peak load minus the monthly coincident peaks associated with all firm point-to-point service customers plus the monthly contract demand reservations for all firm point-to-point service.[257]

Use of the adjusted system monthly peak loads in the rate divisor for flexible point-to-point transmission service eliminates the mismatch concern raised by TAPS.

We have also fully addressed in the Final Rule those arguments objecting to the use of the average of the 12 monthly peaks in determining a firm point-to-point transmission rate and no further discussion is required. The other arguments raised with respect to this section are fact specific and best addressed in individual rate proceedings where the use of an annual system peak versus an average of the 12 monthly peaks in determining a firm point-to-point transmission rate is more appropriately evaluated.

e. Opportunity Cost Pricing

(1) Recovery of Opportunity Costs

The Commission emphasized in the Final Rule that it had fully explained its rationale for allowing utilities to charge opportunity costs in *Northeast Utilities* and *Penelec*.[258] The Commission also explained that transmission providers proposing to recover opportunity costs must adhere to the following requirements:

(1) A fully developed formula describing the derivation of opportunity costs must be attached as an appendix to their proposed tariff;

(2) Proposals must address how they will be consistent with comparability; and

(3) All information necessary to calculate and verify opportunity costs must be made available to the transmission customer.

Rehearing Requests

VT DPS disputes the Commission's holding with respect to opportunity costs and argues that rate filings seeking recovery of opportunity costs should be summarily rejected. It asserts that, contrary to statements by the Commission, courts have not endorsed opportunity cost pricing for transmission customers and maintains that the Commission's failure to consider objections to opportunity cost

[253] FERC Stats. & Regs. at 31,737–38; *mimeo* at 301–04.

[254] FERC Stats. & Regs. ¶ 31,005 (1994).

[255] *See also* NE Public Power District.

[256] FERC Stats. & Regs. at 31,736; *mimeo* at 296–97.

[257] FERC Stats. & Regs. at 31,738; *mimeo* at 303.

[258] Northeast Utilities Service Company (*Northeast Utilities*), 56 FERC ¶ 61,269 (1991), *order on reh'g*, 58 FERC ¶ 61,070, *reh'g denied,* 59 FERC ¶ 61,042 (1992), *order granting motion to vacate and dismissing request for rehearing,* 59 FERC ¶ 61,089 (1992), *aff'd in relevant part and remanded in part,* Northeast Utilities Service Company v. FERC, 993 F.2d 937 (1st Cir. 1993); Pennsylvania Electric Company (*Penelec*), 58 FERC ¶ 61,278 at 62,871–75, *reh'g denied,* 60 FERC ¶ 61,034 (1992), aff'd, Pennsylvania Electric Company v. FERC, 11 F.3d 207 (D.C. Cir. 1993).

pricing on the merits ‘‘directly flouts the court’s ruling’’ in *Northeast Utilities.* According to VT DPS, opportunity costs are inherently unverifiable: ‘‘there are insuperable difficulties in proving the existence of lost opportunity costs in any fashion which can readily and objectively be applied.’’ At a minimum, VT DPS asserts, opportunity costs arising more than five years out are unverifiable and should not be permitted. Moreover, VT DPS argues that the right to challenge the verifiability of opportunity costs is not adequate protection because it is wasteful and burdensome (citing *Cajun Electric Power Cooperative* v. *FERC,* 28 F.3d 173 at 179 (D.C. Cir. 1994) (*Cajun*)).

VT DPS also asserts that the Commission’s treatment is inconsistent with its treatment of gas pipeline pricing policies, which do not permit the assessment of opportunity costs in gas pipeline transportation rates. In addition, VT DPS asserts that opportunity cost pricing for firm transportation service would allow the transmitting utility to charge more for firm transmission of a third party’s power supplies than it charges its own native load for the transmission component of native load service. Finally, VT DPS claims that opportunity cost pricing contravenes Cajun because opportunity cost pricing has a chilling effect on competition in New England and nationally. VT DPS challenges whether a tariff provision that permits the imposition of opportunity costs ‘‘precludes the mitigation of [a utility’s] market power.’’

CCEM asserts that there is no justification for allowing opportunity cost charges when such charges can be eliminated in the secondary or released capacity market, without the discriminatory charge. It notes that opportunity costs are not allowed in any other industry and the Commission should not allow recovery of lost profits.

American Forest & Paper argues that the only way to ensure comparability is to require that transmission services are priced for all customers based upon embedded cost principles (including pricing for expansions). It opposes opportunity cost pricing as being discriminatory because wheeling customers are required to compensate the transmitting utility for its lost opportunities to make economy purchases or sales to benefit native load. It further argues that transmission capacity was not designed to facilitate non-firm, unplanned economy purchases or sales on behalf of native load. American Forest & Paper also asserts that allowing redispatch costs incorrectly presupposes that native load has a superior right to the transmission system. According to American Forest & Paper, neither of these costs (opportunity/redispatch) should be imposed on the former sales, now transmission-only, customers—the transmission customer is no more responsible for the alleged transmission constraint than the existing native load customer who adds to its requirements or the new customer locating in the service territory. It maintains that firm transmission contracts cannot by definition displace opportunity sales because there is no ‘‘opportunity’’ until there is capacity in excess of the firm transmission contractual commitments. In addition, American Forest & Paper asserts that opportunity cost pricing may create difficulties for IPPs, *i.e.*, a lender may not finance projects because of cost uncertainty related to varying revenue flows caused by opportunity cost pricing. It believes that utilities should be required to establish a separate subsidiary to make opportunity purchases or sales on its behalf, which may minimize self dealing.[259] It further asserts that expansions should be subject to embedded cost pricing—unlike in gas pipeline expansions, electric transmission expansions invariably affect an integrated network.

CCEM asserts that, if opportunity cost pricing is maintained, transmission customers should be given the information they need to avert or mitigate opportunity-cost exposure. In particular, it argues that customers need information on the run status and cost of generating units that the transmission provider controls in advance of any proposed redispatch. In addition, CCEM argues that transmission providers should be required to inform customers of a redispatch in advance.

Commission Conclusion

As an initial matter, many of the arguments raised are collateral attacks on *Penelec, Northeast Utilities,* and the Commission’s Transmission Pricing Policy Statement. These matters are not the subject of this proceeding, but rather Order No. 888 simply applies the policy already in place. Therefore, these arguments are not properly raised in this proceeding.[260]

The Commission does not believe that any changes are necessary to its policy on opportunity cost recovery.[261] In the Final Rule, we fully explained our rationale for allowing utilities to charge opportunity costs and no arguments have been presented on rehearing that would persuade us otherwise.

As has been our policy, we will continue to determine the appropriateness of opportunity cost pricing proposals on a case-by-case basis. We continue to believe that opportunity cost pricing will promote efficient decision-making by both transmission owners and users and will not result in unduly discriminatory or anticompetitive pricing. We have stated that because any transmission pricing proposal must meet the comparability standard, we will have ample opportunity to address any concerns that opportunity cost pricing may be unfair and anticompetitive or otherwise inconsistent with the comparability standard, including those concerns raised by CCEM with respect to the need for advance information as to any proposed redispatch.

We note that in compliance filings made pursuant to Order No. 888, most utilities did not make the tariff changes necessary to charge opportunity costs to customers under the pro forma tariff. Absent a subsequent section 205 filing, these transmission providers will not be able to charge opportunity costs under their compliance tariffs. Where transmission providers did modify their tariff to allow for opportunity costs, the Commission is reviewing the proposed charges on a case-by-case basis.

(2) Redispatch Costs

In the Final Rule, the Commission clarified that redispatch is required only if it can be achieved while maintaining

[259] The Commission has effectively achieved this result for opportunity sales by requiring separation of the transmission provider’s wholesale merchant from its transmission operation employees.

[260] These arguments include those made by VT DPS concerning Northeast Utilities and alleged inconsistencies with our natural gas policies.

[261] Under the Commission’s transmission pricing policy, utilities are limited to charging the higher of embedded costs or opportunity/incremental costs. *See* Order on Reconsideration and Clarifying Policy Statement, 71 FERC ¶ 61,195 (1995). Opportunity costs are capped by incremental expansion costs. Opportunity costs are viewed as a form of incremental or marginal cost pricing and include: (1) out-of-rate costs or costs associated with the uneconomic dispatch of generating units necessary to accommodate a transaction; and (2) costs that arise from a utility having to reduce its off-system purchases or sales in order to avoid a potential constraint on the transmission grid. We note that Order No. 888 requires that off-system sales by the transmission provider must be made under the point-to-point provisions of the pro forma tariff.

If a utility expands its transmission system so that it can provide the requested transmission service, it can charge the higher of its embedded costs or its incremental expansion costs. When a transmission grid is constrained and a utility does not expand its system, the Commission has allowed a utility to charge transmission-only customers the higher of embedded costs or legitimate and verifiable opportunity costs (‘‘or’’ pricing), but not the sum of the two (‘‘and’’ pricing).

reliable operation of the transmission system in accordance with prudent utility practice.[262]

The Commission further explained that the recovery of redispatch costs requires that: (1) a formal redispatch protocol be developed and made available to all customers; and (2) all information necessary to calculate redispatch costs be made available to the customer for audit. The Commission also noted that the rates proposed must meet the standards for conforming proposals in the Transmission Pricing Policy Statement.

The Commission also explained in the Final Rule that if the transmission provider proposes to separately collect redispatch costs on a direct assignment basis from a specific transmission customer, the transmission provider must credit these revenues to the cost of fuel and purchased power expense included in its wholesale fuel adjustment clause.[263]

Rehearing Requests

TAPS asserts that there is too much uncertainty with respect to the treatment of redispatch costs. It asserts that the Commission should require a section 205 filing for each corridor/ constraint for which redispatch costs are intended to be shared among the transmission provider and network customers. Once there has been a determination regarding a particular corridor/constraint, TAPS argues that ''it would be appropriate to charge network customers for redispatch costs through a mechanism with no fewer protections than a fuel clause.'' It further argues that redispatch costs, like opportunity costs, should be capped at the cost of the upgrade and, at the least, the Commission should clarify that application of the redispatch sharing provision should be adjudicated in particular cases.

TDU Systems states that it does not object to a redispatch obligation that is necessary to ensure transmission system reliability, but they object to the fact that a transmission provider can determine that a transmission constraint will arise as a result of the sale of additional firm transmission service by the transmission provider. It asks the Commission to clarify that the transmission constraint that would trigger a redispatch obligation cannot be caused by a transmission provider's sale of additional firm transmission capability.

Wisconsin Municipals asks the Commission to clarify that recovery of redispatch costs on a load ratio basis, without a section 205 filing, is limited to when such action is necessary for reliability reasons alone (not for economic reasons), and that in all other circumstances a section 205 filing must be made and costs directly assigned to the customer receiving the economic benefit of the redispatch. It further asserts that if redispatch is allowed for economic reasons, it must be offered on a comparable, non-discriminatory basis to all customers and the transmission provider, provided the beneficiary agrees to accept a direct assignment.

Several utilities argue that redispatch costs are a subset of opportunity costs and that the Commission should not use both terms in the tariff because it implies different standards apply to transmission providers and their customers (*e.g.,* sections 23.1 and 27).[264] They request that the Commission only use the term ''redispatch costs'' in the pro forma tariff and impose the same redispatch obligations on network customers as are imposed on transmission providers.

No rehearing requests addressed the subject of fuel adjustment clause treatment for redispatch costs.

Commission Conclusion

The Commission believes that the obligation to create additional transmission capacity to accommodate a request for firm transmission service should properly lie with the transmission provider, not a network customer.

The Commission clearly established in the Final Rule that utilities are to be given ''substantial flexibility * * * to propose appropriate pricing terms, including opportunity cost pricing [of which redispatch costs are a subset], in their compliance tariff.'' [265] The Commission further required that any such rate proposals must meet the standards for conforming proposals in the Transmission Pricing Policy Statement. Accordingly, TAPS is free to pursue its concerns in any relevant compliance filings.

Tariff sections 33.2 and 33.3 clearly establish that redispatch of all Network Resources and the transmission provider's own resources are only to be performed to maintain the reliability of the transmission system, not for economic reasons. Such costs are to be shared between network customers and the transmission provider on a load ratio basis. Similarly, the Commission clarified in Order No. 888, in modifying the transmission customer's redispatch obligation, that such change was ''to limit the redispatch obligation to reliability reasons.'' [266] Therefore, no further clarification is necessary.

Other redispatching provisions under the tariff (*e.g.,* sections 13.5 and 27) refer to situations where the transmission provider can relieve a system constraint more economically by redispatching the transmission provider's resources than through constructing Network Upgrades in order to provide the requested transmission service. However, in this circumstance, redispatch is conditioned upon the eligible customer agreeing to compensate the transmission provider for such redispatch costs. Section 13.5 of the pro forma tariff further requires that any such redispatch costs to be charged to the transmission customer on an incremental basis must be specified in the customer's service agreement prior to initiating service. These tariff requirements would appear to satisfy Wisconsin Municipals concerns because a section 205 filing must be made to directly assign costs to the customer receiving the economic benefit of the redispatch.

Regarding the argument that only the term ''redispatch costs'' should be used in the pro forma tariff, we note that the Commission followed this suggestion in drafting the pro forma tariff. The only exception is the use of opportunity costs in section 23.1 of the tariff, which caps the compensation for resellers at the higher of: (1) the original rate, (2) the transmission provider's maximum rate on file at the time of the assignment or (3) the reseller's opportunity cost. We further note that their concerns that different standards may be applied to transmission providers than to their customers are addressed in section IV.C.6 (Capacity Reassignment).

f. Expansion Costs

In the Final Rule, the Commission allowed transmission providers to propose any method of collecting expansion costs that is consistent with the Commission's transmission pricing policy.[267] The Commission explained that ''or'' pricing sends the proper price signal to customers and promotes efficiency and further indicated that ''and'' pricing will not be allowed.

The Commission also indicated that any request to recover future expansion

[262] FERC Stats. & Regs. at 31,739–40; *mimeo* at 307–09.

[263] FERC Stats. & Regs. at 31,740; *mimeo* at 309.

[264] E.g., Utilities For Improved Transition, Florida Power Corp, VEPCO.

[265] FERC Stats. & Regs. at 31,739; *mimeo* at 307–08.

[266] FERC Stats. & Regs. at 31,767; *mimeo* at 388.

[267] FERC Stats. & Regs. at 31,741; *mimeo* at 312–13.

costs will require a separate section 205 filing.

Rehearing Requests

Several entities argue that requiring section 205 filings for all transmission expansion costs would impose difficult burdens on transmission providers that use formula rates because they would have to try to distinguish between replacement costs, which are included in formula rates, and expansion costs, which are not.[268] They assert that section 205 filings should be required only for system expansion costs that the transmission provider proposes to recover on a direct assignment or incremental cost basis, but not for costs to be recovered on an embedded cost basis.

TDU Systems maintain that to the extent Order No. 888's provisions concerning direct assignment of transmission facilities indicate a change in the historic policy of rolling transmission investments into rate base, there is a risk TDUs will bear a disproportionate share of the transmission burden relative to transmission owners under the Commission's ''or'' pricing policy. According to TDU Systems, transmission owners should be required to permit customers to substitute their own lower cost capital for that of the owner's.

SoCal Edison and Carolina P&L ask the Commission to clarify that a transmission provider has no obligation to build or upgrade its facilities for short-term firm point-to-point transmission customers (§§ 13.5, 15.4 and 1.13). SoCal Edison states that if a transmission provider is required to build, the Commission should clarify that any costs must be directly assigned to the requesting customer.

Commission Conclusion

The Final Rule does not change the Commission's filing requirements for recovery of transmission expansion costs or other transmission-related expenses. The Rule does not impose a section 205 filing requirement to the extent that existing formula rates do not require that such a filing be made to add transmission investment. However, consistent with the Commission's transmission pricing principles in effect prior to Order No. 888, a decision to price transmission on an incremental cost basis, or to directly assign facilities, are cost assignments that require a section 205 filing.

[268] *E.g.*, Utilities For Improved Transition, Florida Power Corp, VEPCO.

The Final Rule also does not change the Commission's transmission pricing policies. Under our transmission pricing policy, a utility is still permitted to charge the higher of incremental expansion costs ''or'' a rolled-in embedded cost rate. There is no bias in the Final Rule that should cause TDU customers or any other customer to pay a disproportionate share of transmission costs. Moreover, we note that we also encourage joint planning/building options and regional solutions such as RTGs and ISOs.

We do not believe that any change is necessary with regard to the obligation to build or expand. While both sections 13.5 and 15.4 obligate the transmission provider to expand or upgrade its transmission system to accommodate an application for firm point-to-point transmission service, these sections are conditioned upon the transmission customer agreeing to compensate the transmission provider for such upgrade. In light of this compensation requirement, we do not anticipate that transmission providers will be requested to upgrade facilities in order to accommodate requests for short-term point-to-point transmission service. However, in the unlikely event that a short-term firm point-to-point transmission customer agrees to pay the costs of such upgrades, we believe that it is appropriate to require a transmission provider to expand its system to accommodate the request.

g. Credit for Customers' Transmission Facilities

In the Final Rule, the Commission concluded that credits related to customer-owned facilities are more appropriately addressed on a case-by-case basis, where individual claims for credits may be evaluated against a specific set of facts.[269] The Commission stressed that while certain facilities *may* warrant some form of cost credit, the mere fact that transmission customers may own transmission facilities is not a guaranteed entitlement to such a credit. The Commission further explained that it must be *demonstrated* that a transmission customer's transmission facilities are integrated with the transmission system of the transmission provider in order to establish a right to credits. The Commission also noted that consistent with its ruling in *FMPA II*,[270] if a customer wishes not to integrate certain loads and resources, and thereby exclude them from its load ratio share of the allocated cost of the integrated system, it may do so by separately contracting for point-to-point transmission service.

[269] FERC Stats. & Regs. at 31,742–43; *mimeo* at 316–18.

[270] Florida Municipal Power Agency v. Florida Power & Light Company, 74 FERC ¶ 61,006 (1996), *reh'g pending.*

Rehearing Requests

APPA asserts that several differences between the treatment of transmission customers' and transmission providers' facilities are not comparable and must be corrected: (1) transmission providers' facilities include those owned, controlled or operated by the transmission provider, but to obtain credit, transmission customers must own the facilities; (2) transmission providers are under no obligation to engage in joint planning and historically have refused, thus putting the matter beyond the control of the customer; and (3) facilities of the customer must serve all of the transmission provider's power and transmission customers, but a transmission provider can include facilities in rates that serve only certain customers. APPA also maintains that the Commission failed to provide sufficient guidance to allow customers to ascertain the type of transmission facilities for which they can expect to receive credit.

Several entities assert that the standard as to existing customer-owned facilities is inherently ambiguous—the Final Rule preamble says integrated into the ''plans *or* operations'' of the transmitting utility, but section 30.9 of the tariff says the ''planning and operations'' of the transmission provider (emphasis added).[271] Further, they assert, it is unreasonable to require, as a key to integration, that ''the transmission provider is able to provide transmission service to itself or other transmission customers over those facilities'' because it may be that the facilities are necessary to provide network service to the customer that owns the facilities and a credit would be appropriate. They argue that if transmission facilities serve load included in the network customer's network load, the transmission customer should get a credit.

Blue Ridge states that ''[i]f the Commission does intend to change its standard or otherwise codify the result of *FMPA II,* then Blue Ridge urges rehearing and suggests a more analytical, policy oriented approach to the issue.'' (Blue Ridge at 31). It recommends adding the following language to the end of section 30.9 of the tariff concerning credit for new facilities: ''or if such facilities are integrated with, and support the

[271] *E.g.*, NRECA, Blue Ridge, TDU Systems.

Transmission Provider's Transmission system.'' (Blue Ridge at Attachment 1).

FMPA argues that a transmission provider can avoid paying credits for transmission that is functionally the same as that of the transmission provider simply by refusing to jointly plan. It asserts that the Commission should adopt either the Commission's integration test, without requiring joint planning, or a functionality test that considers whether the facilities of the customer and transmission provider are similar. Moreover, it argues that a more inclusive definition of the grid would better achieve comparability and competitive generation markets and would remove incentives to avoid joint planning. It argues that crediting customer-owned transmission also promotes the establishment of regional grids.

Several entities state that the standard as to future network customer-owned facilities should be modified to make joint planning mandatory on the part of the transmission provider, who otherwise has little incentive to cooperate and coordinate.[272] They claim that in joint planning, plans cannot be developed by the transmission provider alone. They further argue that the Commission should not deem the lack of joint planning dispositive of the operation and planning issue.

TAPS asks the Commission to clarify that credits will be provided for existing, as well as future, facilities if the integration requirement is met.

Wisconsin Municipals asks the Commission to clarify that the level of customer-owned credits is a rate issue and that if parties have negotiated provisions for credits, the Final Rule cannot be used by transmission providers to avoid the obligations undertaken in a settlement.

NRECA and TDU Systems assert that the Commission should not abandon its historical practice of rolling in transmission facilities for purposes of transmission pricing; otherwise, the Commission must examine the function of all transmission facilities in a transmission provider's rate base and exclude them if they are not ''integrated'' (referencing Order No. 888 at 317 n.452). They argue that because customers would have to file section 206 filings to enforce this, the Commission should require transmission providers to file under section 205 the identity of those facilities that will be included in the transmission rate base, those that will be excluded, and the supporting data.

Turlock wants the Commission to provide concrete guidelines as to the eligibility of facilities for customer credits. Moreover, Turlock asserts that credits may be appropriate for point-to-point customers as well—especially in Northern California where PG&E, according to Turlock, encouraged customers to build facilities. Turlock finds this particularly important where PG&E has proposed to switch from subfunctionalized ratemaking to system-wide rolled-in ratemaking. It asserts that, if there are system-wide rolled in rates without a credit provision, there may be a violation of the ''or'' pricing policy.

Several entities ask the Commission to clarify that the crediting provision works on a comparable basis for transmission customers and providers.[273] They ask the Commission to clarify that the phrase ''serve all of its power and transmission customers'' in section 30.9 is to be measured by the facilities that the transmission provider rolls into rate base to determine transmission rates and the transmission component of requirements rates. For example, they argue that because AEP rolls radial lines into rate base, comparable customer-owned lines should receive a credit. They also ask the Commission to clarify that the test that facilities are integrated into the planning and operations of the transmission provider is an objective standard that is satisfied by evidence that the transmission provider's load flow studies take into account the transmission customer's facilities. They assert that the standard should not be a subjective one that depends on whether the transmission provider says that it includes customer facilities in its planning and operations.

AMP-Ohio adds that the integration requirement should also be satisfied by evidence that the transmission provider includes costs in its rate base or transmission expenses that are associated with transmission facilities of utilities that it acquires. Michigan Systems also asks that the Commission clarify that the test in section 30.9 is a functional test and not whether the transmission owner says it is integrating its operations.

Michigan Systems states that it has no objection to leaving determinations of credits to rate cases, as an abstract matter, but asserts that the Commission should make clear that it will not implement newly-filed tariffs in a way that imposes multiple or inconsistent charges for transmission in the interim. Otherwise, it asserts, transmission dependent utilities may be out of business if they must wait years to get credit for grid transmission they already own and that they must pay to finance. Michigan Systems also states that it would be illegal to require systems to pay for transmission by applying a load ratio share based on total loads when they have made investments under contracts for transmission to serve a portion of those loads.

TAPS states that the Commission must define what it means by ''integrated.'' TAPS asserts that the term should mean grid facilities used to integrate the network customer's resources and loads. It further asserts that the Commission should continue to use the test whether the facilities serve a comparable function. Unless a proper credit is provided, TAPS maintains, network customers could pay twice for transmission. TAPS adds that without proper crediting, the Commission cannot require load ratio pricing of network service.

TAPS asks the Commission to clarify the method it will use to calculate the credit in individual cases and suggests that the Commission adopt the method TAPS proposed in its initial comments in this proceeding.

With respect to joint ownership of transmission facilities or ownership of transmission facilities through a joint exercise of powers agency (JPA) or a Generation and Transmission Cooperative, TANC asks that the Commission provide for proportionate entitlement to a credit among those who have invested in, and are entitled to the use of, such facilities. TANC also argues that the credit should apply to facilities used to complete a transaction under the transmission provider's point-to-point tariff. Further, TANC asserts that upon a showing that the facilities are integrated, the credit in section 30.9 should be mandatory and asks that the Commission provide guidance as to the method of either calculating or applying the credit.

Commission Conclusion

The Commission reaffirms its finding in Order No. 888 that the question of credits for customer-owned facilities is best resolved on a fact-specific, case-by-case basis.[274] Accordingly, the Commission does not believe that the rehearing requests seeking specific guidance regarding various aspects of

[272] *E.g.,* NRECA, TDU Systems, TAPS.

[273] *E.g.,* IMPA, TAPS, AMP-Ohio, Michigan Systems.

[274] FERC Stats. & Regs. at 31,742; *mimeo* at 316.

customer credits are appropriate for resolution at this time.[275]

In order to conform the Final Rule preamble language with the tariff provisions of Order No. 888,[276] we will modify section 30.9 of the pro forma tariff to provide that a customer may receive a credit for its own facilities if it demonstrates that ''its transmission facilities are integrated into the plans or operations (instead of ''planning and operations'') of the transmission provider to serve its power and transmission customers.'' [277] The intent of section 30.9 of the pro forma tariff is that, for a customer to be eligible for a credit, its facilities must not only be integrated with the transmission provider's system, but must also provide additional benefits to the transmission grid in terms of capability and reliability, and be relied upon for the coordinated operation of the grid. Indeed, in the Final Rule we explicitly stated that the fact that a transmission customer's facilities may be interconnected with a transmission provider's system does not prove that the two systems comprise an integrated whole such that the transmission provider is able to provide transmission service to itself or other transmission customers over these facilities.[278]

The Commission further stated in the Final Rule that where disputes over credits for customer-owned facilities arise, it encourages all parties not to seek formal resolution at the Commission, but to first pursue alternative dispute resolution. In this regard, the customer at the time it is requesting network service could also request that a study be undertaken by the company to analyze the impact and benefit of the customer's facilities provided to the integrated transmission network.

We share the concern of APPA and others that transmission providers have not allowed transmission customers to participate in the planning process for new transmission projects. Allowing potential transmission customers the opportunity to participate in transmission projects is important in ensuring that regional transmission needs are met efficiently. One way of accomplishing this goal is through an RTG, ISO, or other regional entity that has an open planning process. Where such entities do not exist, we strongly encourage public utilities to hold an open season for all transmission expansion projects, including those in response to a service request, so that all entities in the region have an opportunity to identify their future needs and participate in the project.

Finally, requests for the Commission to mandate joint-planning are addressed below in the discussion of section 1.12 of the pro forma tariff.

h. Ceiling Rate for Non-firm Point-to-Point Service

In the Final Rule, the Commission stated that it is important to continue to allow pricing flexibility.[279] The Commission explained that, in accordance with its current policies, the rate for non-firm point-to-point transmission service may reflect opportunity costs. The Commission further explained that, if a utility chooses to adopt opportunity cost pricing, the non-firm rate is effectively capped by the availability of firm service and is not subject to a separately-stated price cap. On the other hand, the Commission explained that, if a utility chooses not to adopt opportunity cost pricing, the non-firm rate is capped at the firm rate.

Rehearing Requests

Duquesne asks the Commission to clarify that the phrase ''the non-firm rate is capped at the firm rate'' does not mean that the Commission is deviating from its principles that non-firm transmission service must be priced in a manner that (i) reflects the interruptibility of the service, and (ii) is economically efficient.

Commission Conclusion

With regard to Duquesne's request, we clarify that the firm transmission rate simply represents a maximum rate or price cap for non-firm transmission prices. We emphasize that non-firm transmission prices should reflect the interruptibility of the service and should promote efficient use of the transmission system, subject to this price cap. Accordingly, while in some circumstances non-firm transmission rates may be set at the firm transmission rate level, the Commission expects that non-firm transmission rates would, in most instances, be priced below the price cap.

i. Discounts

In the Final Rule, the Commission stated that if a transmission provider offers a rate discount to its affiliate, or if the transmission provider attributes a discounted rate to its own wholesale transactions, the same discounted rate must also be offered at the same time to non-affiliates on the same transmission path and on all unconstrained transmission paths.[280] In addition, the Commission required that discounts from the maximum firm rate for the provider's own wholesale use or its affiliate's wholesale use must be transparent, readily understandable, and posted on the transmission provider's OASIS in advance so that all eligible customers have an equal opportunity to purchase non-firm transmission at the discounted rate.[281] Finally, the Commission explained that discounts offered to non-affiliates must be on a basis that is not unduly discriminatory and must be reported on the OASIS within 24 hours of when available transmission capability (ATC) is adjusted in response to the transaction.

Rehearing Requests

Utility Position

A number of utilities assert that the affiliate discounting provision is too broad.[282] SoCal Edison asserts that if the affiliate discounting provision is kept, the requirement to discount similarly for non-affiliates on unconstrained paths should be limited to offers on the same day only for new transmission services and only for the duration of the service offered to the affiliate.

Entergy and Southwestern assert that the Commission should change the discount language, which provides that

[275] Wisconsin Municipals' argument with respect to prior settlements has been previously addressed in Section IV.D.1.c.(2) (Energy Imbalance Bandwidth).

[276] *See* FERC Stats. & Regs. at 31,742–43; *mimeo* at 316–17.

[277] As we noted in *FMPA II*, this fundamental cost allocation concept applies to the transmission provider as well. Just as the customer cannot secure credit for facilities not used by the transmission provider to provide service, the transmission provider cannot charge the customer for facilities not used to provide transmission service. 74 FERC ¶ 61,006 at 61,010 n.48 (1996).

[278] FERC Stats. & Regs. at 31,742–43; *mimeo* at 317.

[279] FERC Stats. & Regs. at 31,743–44; *mimeo* at 319–20.

[280] All offers or agreements to provide rate discounts to affiliates (including the Transmission Provider's wholesale merchant) on a particular path must be posted immediately on the OASIS and be available for a long enough period to allow non-affiliates to obtain the same discounted service on that path and on other paths for which the transmission provider must provide the same discount. We modify below our requirement regarding which other paths must receive the same discount.

[281] The Commission also stated that the same requirements will apply to discounts for firm transmission service. The Commission added that if a transmission provider offers an affiliate a discount for ancillary services, or attributes a discounted ancillary service rate to its own transactions, it must offer at the same time the same discounted rate to all eligible customers. The Commission noted that discounted ancillary services rates must be posted on the OASIS pursuant to Part 37 of the Commission's regulations.

[282] *E.g.*, SoCal Edison, Entergy, Southwestern, PacifiCorp, Montana Power, AEP, Utilities For Improved Transition, EEI.

whenever the transmission provider offers a discount to an affiliate, or attributes a discount to its own transaction, it must offer a comparable discount to all similarly situated transmission customers. Southwestern believes that the Commission does not justify its different treatment of discounts to affiliates and discounts to non-affiliates—section 205(b) of the FPA states that a public utility may not give any *undue* preference or advantage to any person. Southwestern also notes that for gas pipelines, the Commission required that affiliate discounts be available to similarly situated shippers (citing 18 CFR 161.3(h)(1)).

PacifiCorp suggests replacing the last sentence of section 37.6(c)(3) of the OASIS regulations with the following sentence: ''With respect to any discount offered to its own power customers or its affiliates, the Transmission Provider must, at the same time, post on the OASIS an offer to provide the same discount to all Transmission Customers on the same transmission path and on all other unconstrained transmission paths parallel thereto for deliveries to the same Point of Delivery.'' It argues that the Commission's approach of requiring the same discount to all transmission customers on the same path and on all unconstrained transmission paths would discourage discounting, even when done to attract counter-wheeling to relieve constraints.[283]

Several utilities argue that the discount language should be changed to require only that the same discount be offered to all customers on the same path.[284] Otherwise, Montana Power asserts, transmission providers will be reluctant to offer discounts to its own marketers so as to protect revenues on other paths.

AEP suggests that the discount language be changed to require that the discount be made available for all unconstrained paths terminating at the same interface.

Illinois Power argues that the Commission should require discounts for equivalent (*i.e.*, similarly situated) service requests, on the basis of location, term and time of service, which it asserts conforms to the Commission's standards for natural gas pipelines (citing 18 CFR 161.3(h)). Otherwise, it asserts, the Commission's approach will result in inefficient use of scarce transmission capacity and thereby discourage efficient bulk power trading.

[283] *See also* Washington Water Power.

[284] *E.g.*, Montana Power, Allegheny, Puget.

VEPCO asserts that transmission providers must be given more flexibility to accommodate differences in regional wholesale markets and to maximize the movement of economical capacity and energy. It states that a transmission provider will provide discounts only if they are not detrimental to existing committed agreements or potential future revenue—revenue from additional sales must offset the decrease in revenues from making discounts. It suggests that preferential treatment can be reduced by the following constraints: (1) offer the same discount to all transmission requests to the same points of delivery for the same time, and (2) a discount should not apply to service already agreed to but not yet provided at that point. Utilities For Improved Transition adds the following constraint: evaluate request for discount on whether it would increase volume without reducing total revenues.[285] Florida Power Corp asserts that because communications regarding discounts must be posted on OASIS, preferential treatment would be readily apparent.

EEI states that the discount requirement has the potential to arbitrarily reduce the revenue that the transmission provider may be able to obtain over alternative paths that may be unconstrained, but of greater potential value than the path(s) identified as appropriate for discounting. It adds that the requirements for posting discounts should be the same regardless of affiliation and should be limited to the specific transmission path(s) discounted by the transmission provider.

Carolina P&L argues that the Commission should permit selective discounting of non-firm transmission service on a posted-in-advance (on OASIS) basis that will not create a most favored nations situation merely because the transmission provider or an affiliate availed itself of the posted discount.

Customer Position

Tallahassee asks the Commission to clarify that the transmission provider must automatically apply the discount to any eligible customer or, at the minimum, provide actual and timely notice of the discount's availability.

Similarly, PA Coops asserts that ''[i]f transmission service is being discounted to any customer, affiliated or not, for a specific level of service at a specific point in time, it should be equally discounted to all customers receiving the same transmission service. To do otherwise is unduly discriminatory.'' (PA Coops at 11).

[285] *See also* Florida Power Corp.

TAPS asserts that all discounts must be posted in advance, the reasons for the discounts should be transparent, the transmission provider should keep all requests for discounts in a log, and short-lived discounts should not be permitted.

Commission Conclusion

In response to the arguments raised with respect to discounting, we will revise our policy on discounting transmission service. This revised policy will assure consistency with our standards of conduct requirements, which preclude a utility's wholesale merchant function from having access to its transmission system information (including price) not posted on the OASIS that is not otherwise also available to the general public or that is not also publicly available to all transmission users. The revised policy also should result in less opportunity for affiliate abuse and enable better monitoring of potential abuse. Additionally, we have concluded that the same policy should apply regardless of whether the discount is for the transmission provider's own wholesale use (*i.e.*, wholesale merchant function), for the transmission provider's affiliate, or for a non-affiliate.

A transmission provider should discount only if necessary to increase throughput on its system. While the potential for abuse is most obvious in situations involving the transmission provider's own wholesale use or use by an affiliate (own use/affiliate),[286] we must also be concerned with a transmission provider agreeing to discount to non-affiliates in any unduly discriminatory manner. To satisfy these dual concerns, we believe that any ''negotiation'' [287] between a transmission provider and potential transmission customers should take place on the OASIS. Toward this end, we believe three principal requirements are appropriate. (These requirements would remain even after negotiation takes place on the OASIS.)

First, any offer of a discount for transmission services made by the transmission provider must be announced to all potential customers solely by posting on the OASIS. This requirement, which will ensure that all potential transmission customers under

[286] We clarify that own use/affiliate transactions include all transactions where the transmission provider or any of its affiliates is either the buyer, seller, marketer, or broker of wholesale power.

[287] ''Negotiation'' would only take place if the transmission provider or potential customer seeks prices below the ceiling prices set forth in the tariff.

the pro forma tariff will have equal access to discount information, will guard against own use/affiliate customers gaining an unfair timing advantage concerning the availability of discounts.

Second, we will require that any customer-initiated requests for discounts occur solely by posting on the OASIS, regardless of whether the customer is an own use/affiliate or a non-affiliate. We have considered, and rejected at least for now, a more restrictive approach which would require that all discounts be initiated solely through offers by the transmission provider. Under such an arrangement, negotiations for discounts would effectively take place by customers accepting or not accepting the offered discount. While such an arrangement could better protect against affiliate abuse, it might be less efficient.[288] Accordingly, we will permit customer-initiated requests for discounts but will require that such requests be visible (via posting on the OASIS) to all market participants.

Finally, we will require that, once the transmission provider and customer agree to a discounted transaction, the details (*e.g.*, price, points of receipt and delivery, and length of service) be immediately posted on the OASIS. This requirement will be equally applicable regardless of whether the customer is an own use/affiliate or non-affiliate.

We will also revise our policy with respect to the transmission paths on which a discount must be offered. Many petitioners argue that the policy in Order No. 888, particularly that the discount rate must be offered over all unconstrained paths, is too broad, and may provide disincentives for the efficient operation of the transmission grid. Their concerns include, for example, the possibility that the policy would inhibit the transmission provider from offering discounts that would relieve line constraints. For example, PacifiCorp argues that it would be reluctant to offer a discount on northbound power flows that would relieve transmission constraints on transmission paths that are normally used for southbound flows, if by virtue of discounting northbound flows, it would also be required to discount all unconstrained southbound flows. Another concern is that while requiring discounts on all unconstrained paths could conceivably result in more service being provided, it may not have that effect. Since the level of transmission revenues will decline if the discount applies to all unconstrained paths and this, in turn, could reduce the credit to firm transmission users for non-firm service revenues, transmission providers may simply decide not to discount a particular unconstrained path. In light of these persuasive arguments, we will no longer require the transmission provider to provide the same discount over all unconstrained paths.

Under our revised policy, if the transmission provider offers a discount on a particular path, *i.e.*, from a point of receipt to a point of delivery, the transmission provider must offer the same discount for the same time period on all unconstrained paths that go to the same point(s) of delivery on the transmission provider's system. In this regard, a point of delivery includes an interconnection with another control area. Also, if a power purchaser can take delivery at more than one point of delivery (such as two substations serving a municipality), we would consider these to be the same point of delivery for discounting purposes.

This change provides some flexibility to transmission providers to set prices for transmission service efficiently and at the same time maintains the requirement that public utilities provide comparable service at rates that are not unduly discriminatory or preferential. The change is designed to ensure that the transmission owner will provide the same discounted service to its competitors that it provides to itself or its affiliates for their wholesale sales.

The Commission considered requiring the transmission provider offering a discount on a particular path to offer discounts on all unconstrained paths that go from the same points of receipt on the transmission provider's system and decided that such a requirement was not necessary to ensure comparability.

We further clarify that a transmission provider may limit its offers of discounts over the OASIS to particular time periods. There is nothing *per se* unduly discriminatory in offering a discount in one period and not in another.[289]

Finally, we recognize that even with this revised policy utilities may engage in affiliate abuse by offering discounts only at times or along paths that are of advantage to it or its affiliates. While requiring the posting of discount information on the OASIS does not completely eliminate the possibility of affiliate abuse, these procedures will allow ready identification of unduly discriminatory or preferential transactions, and thus make easier the preparation of complaints that the transmission provider is engaging in a pattern of discounting that indicates affiliate abuse, such as offering discounts preferentially at times or on paths that only the transmission provider or its affiliate can take advantage of, without offering discounts at times or on paths that its competitors can take advantage of.

We will require that all ''negotiation'' take place on the OASIS as soon as practicable, as explained in Order No. 889–A.

j. Other Pricing Related Issues Not Specifically Addressed in the Final Rule

(1) Demand Charge Credits

Rehearing Requests

VT DPS argues that demand charge credits for curtailments or interruptions are needed to provide an incentive to utilities to provide high quality service. It points out that the Commission has allowed demand charge credits in the gas pipeline context (citing *Tennessee Gas Pipeline Co.*, 71 FERC ¶ 61,399 at 62,580).[290]

Commission Conclusion

The Commission does not believe that electrical systems will be less reliable as a result of our initiatives on competition and open access in the Final Rule. As such, the Commission does not intend to require demand charge credits on a generic basis to encourage reliable transmission service. However, because the Commission has not mandated any particular rate design methodology under the Final Rule pro forma tariff, customers are free to argue in the compliance filing proceedings or subsequent section 205 proceedings that demand charge credits are reasonable in the context of a particular rate design method.

(2) In-Kind Transactions

Rehearing Requests

CCEM asserts that in-kind transactions in reformed power pool agreements should be abolished because of the uncertainty of valuing non-cash transactions and the potential for cross subsidizing the utilities' generation sales. It contends that a cash equivalent transaction for all formerly in-kind transactions among transmission owners is needed.

[288] For example, requiring the transmission provider to wait to see if an offered 5% discount clears the market would appear to be less efficient than permitting the customer to advise the transmission provider (via the OASIS) of its need for a higher discount in order to take service.

[289] Thus, there is no need to revise contracts to reflect later offered discounts.

[290] *See also* Valero.

Commission Conclusion

To satisfy CCEM's concerns, the Commission concludes that in-kind transactions must be provided on a non-discriminatory basis. The Commission recently found that in-kind transactions (*i.e.*, transactions with payment by energy returned in kind instead of by a monetary charge) with no unbundling requirement ''could hide and, thereby, mask unduly preferential terms and rates,'' which is precisely one of the practices that the Final Rule is intended to remedy.[291] While we will now require that all in-kind transactions be provided on an unbundled basis, we stress that we are not prohibiting in-kind transactions. Utilities are free to enter into contracts that contain in-kind compensation for the wholesale generation component, as long as it unbundles such transactions. Consistent with *Arizona,* unless the other party to the transaction contracts for transmission service under that utility's open access pro forma tariff, that utility must obtain the necessary transmission and ancillary services under the terms of its open access transmission tariff and must separately state the transmission and ancillary service prices that it will recover from the customer.

2. Priority For Obtaining Service

a. Reservation Priority for Existing Firm Service Customers

In the Final Rule, the Commission indicated that a transmission provider may reserve in its calculation of ATC transmission capacity necessary to accommodate native load growth reasonably forecasted in its planning horizon.[292]

Rehearing Requests

This issue is discussed in Section IV.C.5. (Reservation of Transmission Capacity for Future Use by Utility).

b. Reservation Priority for Firm Point-to-Point and Network Service

In the Final Rule, in response to concerns that network service should have a reservation priority over point-to-point service because of pricing differences, the Commission allowed utilities the opportunity to eliminate the differences in pricing between network and point-to-point services by permitting utilities to adopt point-to-point reservations as the customer load.[293] The Commission explained that utilities are free to propose a single cost allocation method for the two services.

In addition, the Commission provided that reservations for short-term firm point-to-point service (less than one year) will be conditional until 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. According to the Commission, these conditional reservations may be displaced by competing requests for longer-term firm point-to-point service. The Commission explained that after the deadline, the reservation becomes unconditional, and the service would be entitled to the same priorities as any long-term point-to-point or network firm service.

Moreover, the Commission explained that the Final Rule pro forma tariff does not propose point-to-point or network service with various degrees of firmness beyond the simple categories of firm and non-firm. It explained that when a customer requests firm transmission service, reservation priorities are established based first on availability, and in the event the system is constrained, based on duration of the underlying firm service request—customers may choose the ''firmness'' of service they want by electing to take non-firm service, or by reserving and paying for firm service.

Rehearing Requests

NRECA and TDU Systems declare that provisions making reservations for short-term firm point-to-point service conditional will not reduce the incentive to cream skim, *i.e.,* a customer has an incentive to submit reservations for very short terms without fear of not getting service because it can always increase its request to match another longer request. They suggest an alternative: all native load, network, and long-term firm (one year or more) requests would be given priority over short-term firm requests, which would have priority over non-firm requests.

Commission Conclusion

The Final Rule has sufficiently minimized the potential for cream skimming. Further, we note that the alternative proposed by NRECA & TDU Systems has substantially been adopted in Order No. 888. Specifically, Order No. 888 provides: (1) public utilities the right to reserve existing transmission capacity needed for native load growth and network transmission customer load growth,[294] and (2) existing transmission customers the right of first refusal.[295] The only entities not covered above—potential long-term firm customers—must submit their service applications as far in advance as practicable.

c. Reservation Priorities for Non-firm Service

In the Final Rule, the Commission found that network economy purchases should have a reservation priority over non-firm point-to-point and secondary point-to-point uses of the transmission system.[296]

Rehearing Requests

North Jersey argues that non-firm service should be allocated on a first-come, first-served basis, and where multiple customers request service at the same time, available capacity should be allocated on a pro rata basis. It asserts that the proposed priority system based on duration of non-firm service would simply encourage non-firm customers to request service for longer durations than needed.

Commission Conclusion

We reject North Jersey's argument that the proposed priority system based on duration of non-firm service would encourage non-firm customers to request service for longer durations than needed. North Jersey ignores the fact that section 14.2 of the pro forma tariff establishes a right for eligible customers with existing non-firm reservations to match any longer term reservation before being preempted.

A related matter is discussed in Section IV.G.3.b below.

3. Curtailment and Interruption Provisions[297]

a. Pro-Rata Curtailment Provisions

In the Final Rule, the Commission found that curtailment on a pro-rata basis is appropriate for curtailing transactions that substantially relieve a

[291] Arizona Public Service Company, Order Addressing Functional Unbundling Issues, 78 FERC ¶ 61,016 (slip op. at 11) (1997) (*Arizona*).

[292] FERC Stats. & Regs. at 31,745; *mimeo* at 323–24.

[293] FERC Stats. & Regs. at 31,746–47; *mimeo* at 326–29.

[294] FERC Stats. & Regs. at 31,694; *mimeo* at 172.

[295] FERC Stats. & Regs. at 31,665 and 31,694; *mimeo* at 88 & 172.

[296] FERC Stats. & Regs. at 31,748; mimeo at 332–33.

[297] In the Final Rule pro forma tariff, the Commission defines curtailment as: ''A reduction in firm or non-firm transmission service in response to a transmission capacity shortage as a result of system reliability conditions.'' (pro forma tariff section 1.7). The pro forma tariff defines interruption as: ''A reduction in non-firm service due to economic reasons pursuant to Section 14.7.'' (pro forma tariff section 1.15). The distinction between curtailment and interruption may have been blurred in Order No. 888 and this order attempts to clarify that distinction.

constraint.[298] The Commission explicitly allowed the transmission provider discretion to curtail the services, whether firm or non-firm, that substantially relieve the constraint.

The Commission also indicated that it would consider granting deference to an alternative curtailment method to avoid hydro spill if such a regional practice is generally accepted and adhered to across the region.

The Commission further found that under network and point-to-point service, the transmission provider may propose a rate treatment (penalty provision) to apply in the event a customer fails to curtail service as required under the Final Rule pro forma tariff and indicated that such proposals will be evaluated on a case-by-case basis on compliance.

Rehearing Requests

PA Com asserts that pro rata curtailment fails to hold native load harmless to the extent practical as required by the FPA. PA Com points out that on January 19, 1994, PJM initiated pro-rata load shedding, in part to preserve economic transactions, leaving customers in Pennsylvania without power during a record cold spell.

VA Com argues that pro rata curtailment may harm native load customers and section 206 complaints are after the fact and of little assistance to native load. VA Com argues that curtailment priority (in order of curtailment) should be: non-firm, contract firm, and then native load, and that utilities should have flexibility to curtail on a pro-rata basis within classes, subject to state curtailment policy.

Several entities argue that provision must be made for preference in curtailment priorities obtained through settlement, through payment of good and valuable consideration, or under existing transmission contracts.[299] Turlock argues that customers should be able to obtain a variation from the pro rata scheme if they can show that they have made either past or future investments to improve constrained facilities and that the quid pro quo for their investment is improved curtailment priority.

Allegheny asks the Commission to clarify that it did not intend to require public utilities to shed (through pro rata curtailment) native transmission load customers in order to preserve some portion of service to through system users of the grid. According to Allegheny, the FPA mandates that service reliability to franchise customers must be maintained and through-system users are not similarly situated to native transmission load customers and should not be treated the same in an emergency because through system customers can protect themselves, but native transmission load customers cannot. Allegheny adds that failure to maintain system reliability would violate section 211 of the FPA.

CCEM asserts that hard and fast priority rules are needed to prevent inconsistent rules from developing for different utilities, pools, or control areas.

Commission Conclusion

Assertions that the pro-rata curtailment provision in the tariff may harm native load customers are misplaced. The Commission clarified in the Final Rule that it was not requiring a pro-rata curtailment of *all* transactions at the time of a constraint, but rather curtailment of those transactions, whether firm or non-firm, that effectively relieve the constraint.[300] The Commission also required that such curtailments be made on a non-discriminatory basis, including the transmission provider's own wholesale use of the system. The Commission further explained that the pro-rata curtailment provision was intended to apply to situations where multiple transactions could be curtailed to relieve a constraint. Of course, if curtailment of multiple transactions is necessary, non-firm service would be curtailed prior to firm service. However, the Commission established that, in emergencies, the transmission provider had the discretion to interrupt firm service under the tariff to ensure the reliability of its transmission system.

In terms of reliability, we believe that sufficient safeguards have been established to protect native load. In particular, the transmission provider is responsible for planning and maintaining sufficient transmission capacity to safely and reliably serve its native load. Order Nos. 888 and 889 permit the transmission provider to reserve, in its calculation of ATC, sufficient capacity to serve native load.

Allegations that a utility did not curtail on a non-discriminatory basis, but instead favored a certain class of customer or type of transaction should be filed in a section 206 complaint proceeding to be reviewed on a case-specific basis. While it is true that such complaints will be processed on an after-the-fact basis, it is only on a fact-specific basis that such complaints can be fully and adequately reviewed.

Additionally, tariff section 14.7 does in fact establish that for curtailment purposes, non-firm point-to-point transmission shall be subordinate to firm transmission service and non-firm service may also be interrupted for economic reasons. However, adopting curtailment schemes based solely on classes of service, as proposed by the VA Com, is inappropriate. Specifically, VA Com's proposal to curtail all non-firm transmission transactions prior to firm transactions could exacerbate an emergency situation. For example, a curtailment could be necessary due to a constraint affecting northbound transactions. However, curtailing all non-firm transactions, including southbound transactions (or counterflows), could worsen the situation. Accordingly, the Commission believes the approach established in the Final Rule of allowing non-discriminatory curtailments of the transaction(s) that effectively relieve(s) the constraint is appropriate.

In response to CCEM's concerns regarding the potential for inconsistent rules for different utilities, pools or control areas, the Commission explained in the Final Rule that any proposed deviations from the non-price terms and conditions of the pro forma tariff, such as regional practices, must be adequately supported by the utility proposing the change.

Finally, Order No. 888 did not abrogate existing contracts;[301] therefore, customers with unique curtailment priorities established by pre-existing contracts would not have these priorities eliminated for the term of the existing contract.

b. Curtailment and Interruption Provisions for Non-firm Service

In the Final Rule, the Commission explained that it had clarified in the pro forma tariff that a network customer's economy purchases have a higher priority than non-firm point-to-point transmission service (citing *AES Power, Inc.*[302]).[303]

The Commission also revised the pro forma tariff to allow the transmission provider to curtail non-firm service for reliability reasons or to interrupt the service for economic reasons (*i.e.*, in order to accommodate (1) a request for

[298] FERC Stats. & Regs. at 31,749; *mimeo* at 335–36.

[299] *E.g.*, Santa Clara, Redding, TANC.

[300] FERC Stats. & Regs. at 31,749; *mimeo* at 335.

[301] We note that in Order No. 888 we partially modified existing economy energy coordination agreements. FERC Stats. & Regs. at 31,666; *mimeo* at 91.

[302] 69 FERC ¶ 61,145 at 62,300 (1994) (proposed order), 74 FERC ¶ 61,220 (1996) (final order).

[303] FERC Stats. & Regs. at 31,750; *mimeo* at 338–39.

firm transmission service, (2) a request for non-firm service of greater duration, (3) a request for non-firm transmission service of equal duration with a higher price, or (4) transmission service for economy purchases by network customers from non-designated resources). The Commission further explained that a firm point-to-point customer's use of transmission service at secondary points of receipt and delivery will continue to have the lowest priority.

Rehearing Requests

For comparability, CCEM asserts that secondary receipt points should be made subordinate to other firm services,[304] but should have priority over non-firm point-to-point transactions. CCEM also argues that non-firm point-to-point service, once scheduled, should not be interrupted to accommodate non-firm service for a network service economy purchase.

VT DPS argues that firm flexible point-to-point service over secondary points of receipt and delivery should have a priority over non-firm point-to-point service (citing sections 14.2 and 14.7 of the pro forma tariff). It argues that this priority is necessary to reflect the fact that point-to-point customers pay for firm service and to be consistent with the treatment of network customers. VT DPS notes that in the natural gas industry the Commission has found that such priority is essential to reflect the fact that firm customers are paying for firm service (citing Order No. 636–B).

APPA asks the Commission to clarify the conditions under which the Commission will allow non-firm service to be interrupted by the transmission provider solely for economic reasons. APPA claims that this clarification is needed so as to prevent interruption of service on a discriminatory basis.

CCEM states that non-firm point-to-point transmission service does not provide the user with a specific capacity reservation, and therefore such service should bear no reservation or demand-like charges and the customer should pay a commodity-only charge only for when the service is being provided.[305] It contends, for example, that if a customer schedules one week of weekly non-firm transmission service and is interrupted on the second day of service, the customer should only pay for the service it used and should have no responsibility to take or to pay for service for the remainder of the week. Alternatively, it argues that if there are reservation charges and the non-firm customer pays for service on a ''take-or pay basis'' regardless of use, non-firm service should not be subject to being bumped once service is scheduled and power is flowing. Moreover, if the non-firm point-to-point transmission customer does pay reservation charges on a ''take-or-pay basis,'' the non-firm reserved capacity should be tradeable in a secondary market.

Commission Conclusion

We reject CCEM's proposal to prevent scheduled non-firm transmission service from being interrupted to accommodate economy purchases for network customers. Non-firm service is provided on an interruptible basis. To the extent CCEM wishes to obtain service that cannot be interrupted to accommodate other transactions, it has the option of requesting firm service in the form of either network or point-to-point transmission service.

APPA's concerns have already been addressed by the Commission. In the Final Rule, the Commission specifically listed the economic reasons that a transmission provider could interrupt non-firm point-to-point transmission to include:

> accommodat[ing] (1) a request for firm transmission service, (2) a request for non-firm service of greater duration, (3) a request for non-firm transmission service of equal duration with a higher price, or (4) transmission service for economy purchases by network customers from non-designated resources.[306]

CCEM's arguments are misplaced in that they focus on the specific rate (including any potential credits for service interruption) that utilities may propose for non-firm point-to-point transmission service. Order No. 888 did not mandate any pricing methodology to be used for non-firm point-to-point transmission service. Rather, the Commission established the minimum non-price terms and conditions necessary to ensure comparable service. As the Commission explained in the Final Rule, utilities are free to propose any rates for non-firm point-to-point transmission in a section 205 filing consistent with the Commission's Transmission Pricing Policy Statement.[307] However, the Commission will evaluate the appropriateness of such proposed rates against the non-price terms and conditions established in the pro forma tariff or other non-price terms and conditions proposed and fully supported by the utility.[308]

The Commission has previously addressed VT DPS' point.[309] Non-firm point-to-point customers pay for non-firm service as their service. Firm point-to-point customers, on the other hand, contract and reserve a specified amount of service over designated points of receipt and delivery. The Commission permitted these firm point-to-point customers to use secondary non-firm service (from points of receipt/delivery other than those designated in their service agreement) on an as-available basis at no additional charge. Because the firm point-to-point customers taking secondary non-firm are accorded this scheduling flexibility at no additional charge, they are properly accorded a lower priority than stand alone, non-firm transmission. In contrast, network customers are responsible for paying for a percentage of total system transmission costs in order to serve their designated network loads whether the energy is from designated network resources or from non-designated resources on an as-available basis.[310] Because the network customer pays a load-ratio share of total transmission costs, it receives a higher priority. Significantly, if any firm point-to-point customer wants to avail itself of the higher priority associated with economy energy purchases under the network tariff, it is free to do so by undertaking the cost responsibilities associated with network service.

Finally, in response to VT DPS, we note that we have chosen different approaches in the electric and natural gas areas. In this regard, we recognize that there is a trade-off between encouraging tradable capacity rights versus maximizing revenues that can be credited against the transmission provider's costs of providing transmission service. On the electric side, fully developed transmission capacity trading rights simply do not exist at this time, and so we have chosen to emphasize an approach that maximizes revenues to be credited to transmission customers. However, we will continue to evaluate our approach in the context of any future transmission rate proposal that is based on the concept of tradable capacity rights.

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[304] A firm point-to-point customer has a right to change its receipt points if capacity is available. These changed receipt points are known as secondary receipt points. The issue addressed here is the priority that is assigned to those secondary receipt points.

[305] *See also* Tallahassee.

[306] FERC Stats. & Regs. at 31,750; *mimeo* at 338.

[307] FERC Stats. & Regs. at 31,769–70; *mimeo* at 395–99.

[308] We note that CCEM has pursued these arguments (raised on rehearing) in utility-specific rate cases and its objections will be addressed there.

[309] See FERC Stats. & Regs. at 31,750; *mimeo* at 338, and AES Power, Inc., 69 FERC ¶ 61,145 at 62,300 (1994) (proposed order), 74 FERC ¶ 61,220 (1996) (final order).

[310] This is comparable to the service a utility provides its native load.

4. Reciprocity Provision

In the Final Rule, the Commission concluded that it was appropriate to require a reciprocity provision in the pro forma tariff.[311] The Commission explained that this provision will be applicable to all customers, including non-public utility entities such as municipally-owned entities and RUS cooperatives, that own, control or operate interstate transmission facilities and that take service under the open access tariff, and any affiliates of the customer that own, control or operate interstate transmission facilities.

The Commission developed a voluntary safe harbor procedure under which non-public utilities would be allowed to submit to the Commission a transmission tariff and a request for declaratory order that the tariff meets the Commission's comparability (non-discrimination) standards. The Commission explained that if it finds that a tariff contains terms and conditions that substantially conform or are superior to those in the Final Rule pro forma tariff, it will deem it an acceptable reciprocity tariff and require public utilities to provide open access service to that non-public utility.

If a non-public utility chooses not to seek a Commission determination that its tariff meets the Commission's comparability standards, the Commission declared that a public utility could refuse to provide open access transmission service. However, any such denial must be based on a good faith assertion that the non-public utility has not met the Commission's reciprocity requirements.

In support of its decision to adopt a reciprocity provision, the Commission explained that it was not requiring non-public utilities to provide transmission access, but was conditioning the use of public utilities' open access services on an agreement to offer open access services in return. The Commission noted that non-public utilities can choose not to take service under public utility open access tariffs and can instead seek voluntary service from the public utility on a bilateral basis.

The Commission further explained that the reciprocity requirement strikes an appropriate balance by limiting its application to circumstances in which the non-public utility seeks to take advantage of open access on a public utility's system. However, the Commission recognized that Congress has determined that certain entities in the bulk power market can use tax-exempt financing by issuing bonds that do not constitute ''private activity bonds'' [312] or by financing facilities with ''local furnishing'' bonds.[313] The Commission stated that it was not its purpose to disturb Congress' and the IRS's determinations with respect to tax-exempt financing. Therefore, the Commission clarified that reciprocal service will not be required if providing such service would jeopardize the tax-exempt status of the transmission customer's (or its corporate affiliates') bonds used to finance such transmission facilities.[314]

With respect to local furnishing bonds, which are available to a handful of public utilities, the Commission noted that Congress, in section 1919 of the Energy Policy Act, amended section 142(f) of the Internal Revenue Code to provide that a facility shall not be treated as failing to meet the local furnishing requirement by reason of transmission services ordered by the Commission under section 211 of the FPA if ''the portion of the cost of the facility financed with tax-exempt bonds is not greater than the portion of the cost of the facility which is allocable to the local furnishing of electric energy.'' [315] So that any local furnishing bonds that may exist do not interfere with the effective operation of an open access transmission regime, the Commission required any public utility that is subject to the Open Access Rule that has financed transmission facilities with local furnishing bonds to include in its tariff a similar provision that it will not contest the issuance of an order under section 211 of the FPA requiring the provision of such service, and will, within 10 days of receiving a written request by the applicant, file with the Commission a written waiver of its rights to a request for reciprocal service from the applicant under section 213(a) of the FPA and to the issuance of a proposed order under section 212(c).

In addition, the Commission limited the reciprocity requirement to the applicant and corporate affiliates. The Commission explained that if a G&T cooperative seeks open access transmission service from the transmission provider, then only the G&T cooperative, and not its member distribution cooperatives, would be required to offer transmission service. However, if a member distribution cooperative itself receives transmission service from the transmission provider, then it (but not its G&T cooperative) must offer reciprocal transmission service over any interstate transmission facilities that it may own, control or operate.

Furthermore, the Commission explained that a non-public utility, for good cause shown, may file a request for waiver of all or part of the reciprocity requirement.

The Commission also explained that the reciprocity requirement will apply to any entity that owns, controls or operates interstate transmission facilities that uses a marketer or other intermediary to obtain access. The Commission added that it would apply the same criteria to waive the reciprocity condition for small non-public utilities as for small public utilities.

Rehearing Requests

Reciprocity Provision—Public Power Position

A number of public power entities argue that the reciprocity provision should be eliminated because the Commission cannot require indirectly what it cannot require directly.[316] Several other public power entities add that the reciprocity obligation is beyond the jurisdiction of the Commission because the transmission obligations of non-public utilities (*e.g.*, municipal utilities) are established and limited to those required by sections 211 and 212 of the FPA.[317] Tallahassee asserts that the Commission's conditioning approach has the effect of excluding an entire class of transmission customer from open access, *i.e.*, those unable to grant reciprocal service. This, Tallahassee asserts, is discriminatory and contrary to the purpose of the Final Rule and the requirements of sections 205, 206 and 212 of the FPA. TANC argues that the Commission does not have the discretion to grant or withhold open access transmission on the condition that the customer consent to doing something that the Commission admits it cannot directly order: ''The Commission has never 'conditioned' its duty to allow only just and reasonable rates on any action by the customer.'' (TANC at 16).

A number of entities challenge the Commission's assertion that the reciprocity requirement for non-public

[311] FERC Stats. & Regs. at 31,760–63; *mimeo* at 370–378.

[312] *See* 26 U.S.C. § 141. Interest on private activity bonds is taxable unless the bonds are qualified bonds for which a specific exception is included in the Internal Revenue Code.

[313] *See* 26 U.S.C. § 142.

[314] The Commission also clarified that reciprocal service will not be required if providing such service would jeopardize a G&T cooperative's tax-exempt status.

[315] 26 U.S.C. § 142(f)(2)(A).

[316] *E.g.*, NRECA, Oglethorpe, AEC & SMEPA, TANC.

[317] *E.g.*, Redding, Tallahassee, TANC, Dairyland.

utilities is voluntary.[318] Dairyland contends that the alternative of seeking a bilateral agreement is illusory—even if it could be obtained—because Order No. 888 provides that any bilateral wholesale coordination agreement executed after July 9, 1996 will be subject to open access requirements. Dairyland argues that the phrase ''subject to open access requirements'' presumably would include the reciprocity requirement for non-public utilities.

AEC & SMEPA assert that there is no record support for the contention that non-public utilities are responsible for closed systems or that such systems, if any, have an impact on the market.

NRECA asserts that if the reciprocity provision is retained, the Commission should ''modify its terms to incorporate the statutory standards and protections which FPA sections 211 and 212 contain.'' [319]

Umatilla Coop asks the Commission to clarify that distribution cooperatives will not become subject to the reciprocity requirements merely because they purchase power from affiliated cooperatives that are acting as power marketers. TDU Systems assert that a cooperative should not have to render reciprocal service if it would interfere with its ability to obtain RUS loan financing.

TAPS declares that the transmission provider alone should not have access to third-party systems through reciprocity. It maintains that the utility's long-term transmission customers should also be afforded access to those third-party systems so that the transmission provider does not have a competitive advantage. TAPS argues that a third-party should be required to have an open access tariff available.

Reciprocity Provision—Utility Position

A number of utilities argue that the exemption from reciprocity for distribution cooperatives should be eliminated.[320] EEI and Montana-Dakota Utilities assert that G&Ts could eliminate their reciprocity obligation by selling or transferring their transmission facilities to their distribution owner/members. Southwestern argues that the exception for distribution cooperatives puts public utilities at a competitive disadvantage in that distribution cooperatives can use a public utility's system to compete with the public utility, but a public utility cannot use the distribution cooperatives' systems to compete to sell power to their customers.[321] It adds that the exception allows distribution cooperatives to hide behind shell G&Ts. For example, Southwestern argues that Golden Spread Electric Cooperative is a shell G&T because it owns only small amounts of facilities. It concludes that reciprocal access may become especially important if a state implements a retail access plan because section 211 cannot be used to obtain transmission for retail access over a distribution cooperative's system.

Southern claims that cooperatives have argued in courts and in Congress that a G&T cooperative and its distribution cooperative owners are unified economic interests in which the interest of the whole is equal to the sum of the parts, and that federal courts have upheld this view (citing one case—City of Morgan City v. South Louisiana Electric Cooperative Ass'n, 49 F.3d 1074 (5th Cir. 1995) (*Morgan City*)).

EEI claims that clarification of certain aspects of reciprocity is needed: (1) public utilities may not be able to determine if reciprocal service is comparable because non-public utilities do not have to provide Form 1 data, and thus non-public utilities should be required to submit additional data; (2) non-public utilities should be required to functionally unbundle, charge rates to themselves and others that reflect the cost of using the system themselves, comply with the standards of conduct, and establish an OASIS; (3) non-public utility members of an RTG should be required to offer reciprocal service comparable to that provided by public utility members; and (4) a non-public utility should be required to provide all services it is reasonably capable of providing. Carolina P&L adds that a customer should be required to provide the full panoply of transmission services that it is capable of providing because the customer has a right to take any type of service from the transmission provider even though it may only choose one particular service.

Tucson Power asks the Commission to clarify how it will determine the comparability of a non-public utility's tariff. It asserts that first, under the safe harbor option, the Commission should clarify (1) that non-public utilities must comply with the Commission's rules of practice and procedure, and (2) how it will determine that the rates, terms and conditions of the reciprocal service are comparable to the service the non-public utility provides itself (Tucson Power argues that this could require submittal of data comparable to that contained in Form 1). Second, the Commission should eliminate the option that would require the public utility to determine whether the request by the non-public utility is consistent with the tariff. Finally, under the RTG option, the Commission should clarify that the evidentiary requirements for non-public utilities that are members of an RTG will be the same as for non-public utilities using the safe harbor procedure, *i.e.*, any disputes regarding compliance should be resolved by the Commission, not the RTG.

A number of utilities assert that the Commission should not limit the right to obtain reciprocity only to the public utility that provides the transmission service because power could actually flow over other public utilities' transmission lines. They argue that the Commission should ensure that open access transmission is as widely available as possible.[322] EEI asserts that Federal power marketing agencies, including BPA, should be required to provide comparable open access transmission.

Oklahoma G&E argues that Order No. 888 violates the Constitution's equal protection principles because it does not require universal open access. It asserts that the Commission has created an arbitrary distinction between classes of utilities that is unrelated to the Commission's objective and therefore is constitutionally invalid. Oklahoma G&E contends that the proper approach is to proceed under EPAct for all transmitting utilities on a case-by-case basis.

Detroit Edison asks the Commission to clarify that the supplier and the recipient of power are direct beneficiaries and must be considered transmission customers for reciprocity purposes. Otherwise, Detroit Edison contends, parties from jurisdictional transmission transactions may be able to evade reciprocity.

Reciprocity Provision—Other Arguments

CCEM argues that reciprocity should be expanded to require a transmission customer obtaining open access service also to provide open-access transmission service to all eligible customers. Otherwise, CCEM maintains, transmission owners will be able to penetrate into wholesale markets controlled by non-public utilities, but power marketers will not.

[318] *E.g.*, NRECA, Dairyland, TDU Systems, AEC & SMEPA.

[319] NRECA at 29. NRECA specifically lists the following: reliability of electric service; impairment of contracts; ability to cease service; all costs associated with the service must be recovered; retail marketing areas; and prohibitions on retail wheeling and sham wholesale transactions. *See also* Oglethorpe.

[320] *E.g.*, EEI, Entergy, Montana-Dakota Utilities, Southwestern, Oklahoma E&G, Southern.

[321] *See also* Oklahoma E&G.

[322] *E.g.*, Montana-Dakota Utilities, Southern, EEI.

CCEM asks the Commission to clarify that when a non-public utility obtains open access from a power pool, member of a power pool, or parties to some form of bilateral coordination agreement, its reciprocity obligation extends to all eligible customers, including all members of the pool or parties to the agreement.

Commission Conclusion

We continue to believe that it is appropriate to condition the use of public utility open access tariffs on the agreement of the tariff user to provide reciprocal access to the transmission provider. No eligible customer, including a non-public utility, that takes advantage of non-discriminatory open access transmission tariff services should be allowed to deny service or otherwise discriminate against the open access provider. As we explained in the Final Rule,

> [n]on-public utilities, whether they are selling power from their own generation facilities or reselling purchased power, have the ability to foreclose their customers' access to alternative power sources, and to take advantage of new markets in the traditional service territories of other utilities. While we do not take issue with the rights these non-public utilities may have under other laws, we will not permit them open access to jurisdictional transmission without offering comparable service in return. We believe the reciprocity requirement strikes an appropriate balance by limiting its application to circumstances in which the non-public utility seeks to take advantage of open access on a public utility's system.[323]

Contrary to arguments raised on rehearing, we are not *requiring* non-public utilities to provide transmission access. Instead, we are 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.[324] It would not be in the public interest to allow a non-public utility to take non-discriminatory transmission service from a public utility at the same time it refuses to provide comparable service to the public utility. This would restrict the operation of robust competitive markets and would harm the very ratepayers that Congress has charged us to protect. Very simply, we refuse to take a head-in-the-sand approach and order a remedy for undue discrimination that will permit the beneficiaries of the remedy to engage in unduly discriminatory actions.

Moreover, non-public utilities are free to seek from a public utility a waiver of the open access tariff reciprocity condition. We note that this is a modification of our statements in Order No. 888, in which we said that non-public utilities could seek a voluntary offer of transmission service from a public utility on a bilateral basis. Since the time Order No. 888 issued, we have concluded that except in unusual circumstances, public utility services should be provided pursuant to the open access tariff and not pursuant to separate bilateral agreements.[325] This applies to all customers, including non-public utilities. Therefore, rather than requesting a bilateral agreement in order to avoid the reciprocity condition, non-public utilities instead may ask a utility for a waiver of the reciprocity condition in the utility's open access tariff. We disagree with Dairyland that this type of alternative approach is illusory. If the public utility chooses voluntarily to grant a waiver, the reciprocity condition would not apply.

We reject NRECA's request that we incorporate in the reciprocity condition the statutory standards and protections of FPA sections 211 and 212. NRECA states on rehearing that mandated services to third parties would endanger cooperatives' ability to provide service to members, or increase members' costs. It further states that sections 211 and 212 provide substantive protections to ensure continued service to the transmitting utility's own customers, and to avoid their subsidization of services to third parties. NRECA appears to believe that these substantive protections are not provided outside the context of sections 211 and 212. We disagree. We believe the protections that NRECA is seeking are contained in the pro forma tariff and, as required by section 6 of the tariff, the non-public utility must offer its service on similar terms and conditions.[326]

We also reject requests that we not grant the exception to reciprocity provided in the Final Rule for distribution cooperatives and joint action agencies. We continue to believe that if a G&T cooperative seeks open access transmission service from the transmission provider, then only the G&T cooperative, and not its member distribution cooperatives, should be required to offer transmission service.[327] Without a corporate affiliation between G&T cooperatives and their member distribution cooperatives, we do not believe it is appropriate to apply the reciprocity condition to the member distribution cooperatives. To do so would result in the member distribution cooperatives being bound by their G&T cooperatives.[328]

Carolina P&L has brought to our attention a possible misunderstanding as to the meaning of comparable transmission service that a non-public utility must agree to provide as a condition of using an open access tariff. Because a non-public utility may choose any type of service from a public utility transmission provider that the transmission provider provides or is capable of providing, we clarify that a non-public utility seeking to take service under the transmission provider's open access tariff must likewise agree to offer to provide the transmission provider any service that the non-public utility provides or is capable of providing on its system in order to satisfy reciprocity. We note that in the Final Rule we explained that "[a]ny public utility that offers non-discriminatory open access transmission for the benefit of customers should be able to obtain the same non-discriminatory access in return." [329] In this regard, because a public utility must have an OASIS and a standard of conduct for employee separation, so must a non-public utility that seeks open access transmission from a public utility.[330]

[323] FERC Stats. & Regs. at 31,762; *mimeo* at 374.

[324] As discussed *infra*, non-public utilities may seek a waiver of the reciprocity condition. We therefore reject Tallahassee's argument that we are excluding an entire class of transmission customer from open access, *i.e.*, those unable to grant reciprocal service. If the Commission determines that a particular customer truly is not able to reciprocate, the reciprocity condition can be waived. These situations are obviously different from situations involving entities that do not wish to provide reciprocal service.

[325] *See* Public Service Electric & Gas Company, 78 FERC ¶ 61,119, slip op. at 4 and n.7 (1997).

[326] With regard to the basic substantive protections such as reliability, opportunity to recover costs, and the standards for rates, terms and conditions of transmission service, we see no relative distinctions between sections 211 and 212 and sections 205 and 206 of the FPA.

[327] In response to Southern's citation to *Morgan City*, while this case provides some background as to the relationship between G&T cooperatives and distribution cooperatives, it in no way suggests that the relationship rises to the level of a corporate affiliation.

[328] However, in response to Umatilla Coop, we clarify that to the extent a distribution cooperative purchases power from an affiliated cooperative that is acting as a power marketer, the distribution cooperative will be subject to the reciprocity condition because of the marketing affiliate relationship between the two. Moreover, as we explained in the Final Rule, the reciprocity condition also applies to any entity that owns, controls or operates transmission facilities and that uses a marketer or other intermediary to obtain access. FERC Stats. & Regs. at 31,763; *mimeo* at 378.

[329] FERC Stats. & Regs. at 31,760; *mimeo* at 370.

[330] *See* South Carolina Public Service Authority (*Santee Cooper*), 75 FERC ¶ 61,209 (1996); Central Electric Cooperative, Inc., 77 FERC ¶ 61,076 (1996). Of course, the non-public utility can always seek a waiver of the OASIS and standard of conduct requirements. Such a waiver request will be

At the same time, however, we deny requests to expand the reciprocity condition.[331] Although we believe that non-public utilities should provide open access transmission as a matter of policy, to require non-public utilities to offer transmission service to entities other than the public utility transmission providers increases the chances that they could lose tax-exempt status. Accordingly, we have adopted a policy that recognizes the statutory tax restrictions placed on non-public utilities but also balances the fundamental unfairness of requiring a utility to make its facilities available to someone who could use that access to the competitive disadvantage of the utility. Ultimately the public interest is best served by nationwide open access and, if the tax issue is favorably resolved, we may revisit the matter.

Moreover, in response to Detroit Edison, we take this opportunity to clarify that reciprocity would apply to a wholesale purchaser if a generation seller obtains transmission service from a public utility to sell to such purchaser and such purchaser owns, operates or controls interstate transmission facilities. The same would be true where the seller owns, operates and controls interstate transmission facilities and the buyer arranges for the transmission service. Just as with marketers or other intermediaries, we do not intend to allow reciprocity to be defeated simply on the basis of whether the seller or buyer requests transmission. Such a result would elevate form over substance.

With respect to TDU System's assertion that reciprocal service should not have to be rendered if it would interfere with RUS loan financing, we note that we have already indicated that reciprocal service need not be provided if tax-exempt status would be jeopardized. If TDU Systems is arguing that we should not require reciprocal service if RUS attaches such a condition in its regulation of RUS-financed cooperatives, we reject such an argument. Such cooperatives have the option to seek bilateral service agreements.

We reject EEI's and Tucson Power's argument that non-public utilities must provide Form 1 data in order to provide comparable service. The Form 1 data would be relevant only if the Commission were setting non-public utilities' rates. Such a detailed review is not necessary, however. *See Santee Cooper*, 75 FERC ¶ 61,209 (1996). Similarly, there is no need to have non-public utilities follow our Rules of Practice and Procedure to satisfy reciprocity.

evaluated under the same criteria applicable to a waiver requests by a public utility.

[331] In reaching this conclusion, we note that the electric industry currently conducts business using contract path pricing. If we are presented with a regional proposal for flow-based pricing, we will reconsider whether there is a need to expand reciprocity as requested by certain entities.

Rehearing Requests

Safe Harbor/Waiver Provisions

NRECA states that the following issues related to safe harbor status and declaratory order requests need clarification: (1) under what statutory authority is the Commission considering such petitions? (2) what rights do non-public utilities have to obtain review of Commission determinations with which they disagree? (3) how closely will a reciprocal tariff have to conform to Order No. 888 to win approval? (4) will non-public utilities have to pay the standard fee (now $11,550) with a declaratory order petition?[332] and (5) will the Commission allow non-public utilities to include a stranded cost recovery provision similar to section 26 of the pro forma tariff?[333]

Oglethorpe asserts that the Commission should not use these procedures to assert jurisdiction over non-public transmitting utilities. Dairyland contends that requiring non-public utilities to invoke declaratory order or waiver proceedings just to assert the clear statutory protections contained in sections 211 and 212 is unwarranted.

TANC declares that the safe harbor provisions do not cure the problems created by reciprocity. It argues that the safe harbor provision expands the transmission access that must otherwise be offered by non-public utilities, *i.e.*, rather than just providing reciprocal service to the transmission provider, under the safe harbor provision, the non-jurisdictional entity must offer open access to any eligible customers.

Blue Ridge alleges that the safe harbor and waiver provisions face practical administrative problems. It asserts that a waiver itself will result in disputes and that the application of the waiver principle to non-public utilities is based on questionable statutory authority. It requests that the Commission add the following language to section 6 of the tariff: ''If the Transmission Customer is a non-public utility, the Transmission Provider must demonstrate a need for transmission service from such entity.'' (Blue Ridge at 39).

[332] NRECA raises comparable questions with respect to waiver procedures.

[333] *See also* TANC.

TAPS asks that the Commission accord the filing of a waiver application by a small non-public utility system, or inclusion in an application of a sworn statement of inapplicability, the same protections afforded larger non-public utility systems that file under the safe harbor mechanism.

Arkansas Cities ask the Commission to clarify that ''utilities like Arkansas Cities' members, which do not operate a control area, do not own 'transmission' facilities and primarily purchase energy for resale at retail are not subject to the transmission reciprocity condition contained in Order 888, and are also not required to file a request for a waiver from the requirements of Order 888 and 889.'' (Arkansas Cities at 18–19)

SWRTA and NWRTA ask the Commission to clarify that RTGs have the authority to issue limited waivers of the reciprocity requirements of Order Nos. 888 and 889 to qualifying non-public utility members of RTGs, and that the Commission will accord deference to an RTG's determination with respect to a non-public utility member's request for waiver of, or exemption from, these requirements.[334] They note that SWRTA's bylaws have a Commission-approved waiver process and disputes would go to arbitration or to the Commission.

Southern and EEI argue that public utilities should have a parallel ''safe harbor''—the right to seek a declaratory order as to whether the transmission service being offered by a non-public utility satisfies its reciprocity obligation.

Tallahassee asks that the Commission clarify the good faith assertion a public utility must make that the non-public utility has not met the reciprocity requirements. It asserts that the section 211 good faith request rules form an appropriate standard by which to measure a good faith assertion.

Commission Conclusion

Several entities raise procedural and jurisdictional concerns with respect to our safe harbor and waiver provisions. At the outset, we emphasize that this Commission does not have jurisdiction over non-public utilities under sections 205 and 206 and that the safe harbor mechanism and waiver provisions do not, and indeed cannot, give us such jurisdiction. Rather the safe harbor and waiver procedures are voluntary means for non-public utilities to obtain a Commission determination that they meet the reciprocity condition in the open access tariffs and thereby avoid

[334] WRTA supports NWRTA in NWRTA's rehearing request.

potential delays or denials of open access service based on allegations that the transmission requestor does not meet reciprocity. In *Santee Cooper,* issued subsequent to the Final Rule, the Commission recognized that it lacks jurisdiction under sections 205 and 206 over transmission rates, terms and conditions offered by non-public utilities, but explained that it has the authority to evaluate non-jurisdictional activities to the extent they affect the Commission's jurisdictional responsibilities.

We clarify that non-public utilities that disagree with a Commission determination are free to request rehearing of a Commission order, as occurred in *Santee Cooper.* If aggrieved by the Commission's final order, they may appeal under section 313 of the FPA. Also, with respect to the filing fee a non-public utility entity would have to pay in making a declaratory order request, the Commission in *Santee Cooper* explained that its regulations specifically exempt states, municipalities and anyone who is engaged in the official business of the Federal Government from filing fees.[335] Because of the nature of the safe harbor and waiver provisions, we will also waive the filing fee for declaratory orders for all other non-public utilities in these circumstances.

As to the question of how closely a reciprocal tariff will have to conform to Order No. 888, the Commission determined in *Santee Cooper* that:

> As part of its compliance filing * * * the Authority must submit a single tariff that conforms to the Open Access Rule *pro forma* tariff.[336]

The Commission further explained that ''[t]he Open Access Rule requires that reciprocity tariffs contain terms and conditions which substantially conform or are superior to those in the Open Access Rule *pro forma* tariff.'' [337] We clarify, however, that in that case the utility chose to offer an open access tariff, whereas Order No. 888 provides, as a condition of service, that reciprocal access be offered to only those transmission providers from whom the non-public utility obtains open access service. Therefore, a non-public utility may so limit the use of any voluntarily offered tariff, as long as the tariff otherwise substantially conforms to the pro forma tariff. We also note that non-public utilities are free to enter into bilateral agreements to satisfy the reciprocity condition. With respect to such bilateral reciprocal agreements, we must leave these agreements to case-by-case determinations. Which terms and conditions may be necessary for a non-public utility to provide reciprocal service to the public utility in a bilateral agreement is necessarily a fact-specific matter not susceptible to resolution in a generic rulemaking proceeding. Additionally, we clarify that non-public utilities may include stranded cost recovery provisions in any reciprocity tariffs that they may file.[338]

In response to TANC's concern that the safe harbor provision expands the transmission access that must otherwise be offered by non-public utility entities, and Blue Ridge's concern that the safe harbor and waiver provisions raise practical administrative problems, we emphasize that both of these procedures are purely voluntary and a non-public utility can avoid any perceived problems simply by not taking part in either process. We note that several entities have voluntarily availed themselves of these procedures without any apparent hardships.[339]

Arkansas Cities' various waiver requests are best addressed on a case-by-case basis that permits a full airing of the factual circumstances surrounding each entity seeking a waiver. As we explained in a recent order, ''the Commission will not address waiver requests in a generic rulemaking proceeding, but will require entities seeking waiver of all or part of Order Nos. 888 and 889 to submit separate, fact-specific requests. * * *'' [340]

EEI's and Southern's request that public utilities be provided a parallel ''safe harbor'' (*i.e.,* the right to seek a declaratory order as to whether the transmission service being offered by a non-public utility satisfies its reciprocity obligation) is denied. In the Final Rule, we explained that a public utility may refuse to provide open access transmission service to a non-public utility if its denial is based on a good faith assertion that the non-public utility has not met the Commission's reciprocity requirements. [341] Moreover, a public utility can file a petition to terminate transmission service if a non-public utility is violating the reciprocity condition of its open access service agreement with the public utility.[342]

In response to SWRTA and NWRTA's request to clarify that RTGs have the authority to issue limited waivers of the reciprocity conditions of the Order No. 888 pro forma tariffs, we recognize that RTGs have procedures in place to resolve disputes that may arise concerning a non-public utility member's request for service from a public utility member. Because RTGs have these dispute resolution procedures in place, we clarify that RTGs, which are in themselves reciprocal voluntary arrangements, may determine whether to apply reciprocity between and among member public utilities and member non-public utilities, subject to the RTG dispute resolution procedures authorized by this Commission.

Rehearing Requests

Retail Wheeling

Dairyland contends that the Commission improperly requires a non-public utility to provide retail wheeling if it uses the open access tariff of a public utility that allows retail access either voluntarily or as part of a state-mandated program.

Commission Conclusion

Contrary to Dairyland's contention, nothing in the Final Rule requires a non-public utility to provide retail wheeling. Section 212(h) of the FPA explicitly prohibits the Commission from ordering retail transmission directly to an ultimate consumer. If a non-public utility offers reciprocal service, its tariff would have to include the same explicit provision contained in the pro forma tariff, which states that an eligible customer cannot obtain transmission that would violate section 212(h) of the FPA, unless pursuant to a state program that requires the transmission provider to offer such wheeling.

Rehearing Requests

OASIS

Southern argues that the Commission should explicitly require that non-public utilities must comply with Order No. 889 as part of the reciprocity obligation.

Commission Conclusion

We agree with Southern and, as discussed above, absent a waiver, will

[335] 75 FERC at 61,694–95 (citing 18 CFR 381.108).

[336] 75 FERC at 61,701.

[337] *Id.*

[338] Because we have not extended the reciprocity condition to rate aspects of a non-public utility's tariff, we would not evaluate any stranded cost recovery mechanism and, as with respect to all terms and conditions of non-jurisdictional tariffs, the Commission is without jurisdiction to enforce such a charge.

[339] *E.g., Santee Cooper,* Omaha Public Power District (filed petition for declaratory order on October 17, 1996, which was docketed as NJ97–2–000), Southern Illinois Power Cooperative (filed petition for declaratory order on October 8, 1996, which was docketed as NJ97–1–000).

[340] 76 FERC ¶ 61,009 at 61,027 (1996).

[341] FERC Stats. & Regs. at 31,761; *mimeo* at 372.

[342] For the same reason, we deny Tallahassee's request that we clarify the good faith assertion a public utility must make that the non-public utility has not met the reciprocity condition.

require non-public utilities to comply with Order No. 889 as part of the reciprocity obligation.

Rehearing Requests

Foreign Entities

In the Open Access Rule, we decided that a foreign entity that otherwise meets the eligibility criteria should be able to obtain service under a United States public utility's open access tariff. However, like United States non-public utilities (which also are not under our section 205–206 jurisdiction), a foreign entity that owns or controls transmission facilities and that takes transmission service under a United States public utility's open access tariff must comply with the reciprocity provision in the tariff.[343] The reciprocity provision ensures that when a public utility provides service under its open access tariff to a transmission-owning entity that is not subject to the open access requirement, the public utility will be able to receive service in turn from that entity. In our discussion of the reciprocity provision, we pointed out that if a non-jurisdictional entity that owns or controls transmission does not wish to provide service to the public utility, it can choose not to use the public utility's open access tariff and can instead seek voluntary service from the public utility on a contractual basis.[344]

On rehearing, Ontario Hydro argues that the Commission has ''unilateral[ly] impos[ed]'' the reciprocity requirement on foreign entities in violation of the North American Free Trade Agreement (NAFTA).[345] It declares that

[u]nder the principle of national treatment, the citizens of each party to NAFTA * * * are allowed the same market access within another treaty party's market as is provided to the citizens of such other party. A party to these agreements cannot withhold access to its market by conditioning it upon receipt of equal access into the market of another party, because the result would be market access less favorable for the other party * * * than that accorded the party's own citizens.[346]

Ontario Hydro claims that the Open Access Rule ''makes open access the law of the land for wholesale transmission service within the United States * * *'' and that Canadian entities are thus entitled to such access on an unconditional basis.[347] Next, it accuses the Commission of trying to ''coerce'' Canada to ''conform its market access policy'' to United States policy and of ''impos[ing] U.S. regulatory policies'' on Canadian markets.[348] Finally, Ontario Hydro argues that even aside from the NAFTA issue, under the FPA the Commission does not have jurisdiction over foreign entities and thus cannot require reciprocity.

Commission Conclusion

We disagree with Ontario Hydro's claim that NAFTA's national treatment principle requires us to allow a Canadian transmission-owning entity (or its corporate affiliate) to take advantage of a United States public utility's open access tariff—a tariff we have required the utility to adopt—while simultaneously refusing to allow the United States utility to use the Canadian entity's transmission facilities. NAFTA's national treatment principle requires that each signatory ''accord national treatment to the goods'' of other signatories in accordance with Article III of the General Agreement on Tariffs and Trade (GATT).[349] National treatment means that the United States ''must not discriminate between foreign and domestic energy on the basis of nationality * * *'' and that Canadian electricity must be treated ''no less favorabl[y] than U.S. electricity, under all U.S. laws and rules respecting the sale, * * * distribution, and use of * * * electricity.'' Thus, this Commission must accord Canadian energy supplies treatment that is no less favorable than the treatment accorded United States supplies.[350] Ontario Hydro's interpretation, however, would twist this principle into a requirement that Canadian entities be treated better than United States entities, including United States non-public utilities that are subject to the reciprocity condition.[351]

Under Order No. 888, all public utility open access tariffs contain a reciprocity condition that applies to all users of the tariff within the United States, including United States non-public utilities, unless the condition is waived either by the Commission or the public utility provider. Under the reciprocity condition, non-public utilities do not have to offer an open access tariff (i.e., a tariff that offers transmission service to any eligible customer), but rather must offer comparable transmission services only to those transmission providers whose open access tariffs the non-public utility uses.[352] The same condition applies to foreign utilities. Thus, Ontario Hydro is in plain error in arguing that application of the reciprocity condition to foreign entities would result in less favorable treatment than that accorded to United States citizens. Ontario Hydro's reading of NAFTA would place transmission-owning Canadian entities (or their corporate affiliates) in a *better* position than any domestic entity; not only would Canadian entities not be subject to the open access requirement, but, unlike domestic non-public utilities, they would be able to use the open access tariffs we have mandated without providing *any* reciprocal service. Ontario Hydro has cited no precedent demonstrating that NAFTA imposes such an unreasonable requirement.[353]

Moreover, we are not ''coercing'' Canada into adopting our policies or ''imposing'' open access on Canadian entities; we are simply placing the same condition on a Canadian entity's use of a United States utility's open access tariff as on a domestic non-public utility's use of that tariff. However, consistent with the approach we have taken in other contexts involving foreign utilities seeking to transact in United States electricity markets, we are amenable to a variety of approaches for Canadian utilities to meet the reciprocity condition.[354]

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[343] FERC Stats. & Regs. at 31,689; *mimeo* at 156.

[344] FERC Stats. & Regs. at 31,761; *mimeo* at 373.

[345] 32–3 Int'l Legal Materials 682 (1993); 19 U.S.C.A. § 3301 *et seq.* (1995 Supp.)(legislation implementing NAFTA).

[346] Ontario Hydro at 4–7.

[347] Ontario Hydro at 5.

[348] Ontario Hydro at 5, 3.

[349] NAFTA Article 301, *citing* GATT, 61 Stat. A5, A18–A19 (1947). ''Goods'' under NAFTA include transmission service. NAFTA, Articles 606, 609.

[350] Iroquois Gas Transmission System, L.P., *et al.*, 53 FERC ¶61,194 at 61,700–01 (1990), *aff'd sub nom.* Louisiana Association of Independent Power Producers and Royalty Owners v. FERC, 958 F.2d 1101 (D.C. Cir. 1992), *quoting* United States-Canada Free Trade Agreement Implementation Act of 1988, Report of the Committee on Energy and Commerce, House of Representatives, H.R. Rep. No. 100–816, Part 7, 100th Cong., 2d Sess. at p. 7 (1988). The Free Trade Agreement is a predecessor to NAFTA.

[351] We have no section 205–206 jurisdiction over non-public United States utilities, just as we have no jurisdiction over foreign entities. Ontario Hydro's claim that the Open Access Rule ''makes open access the law of the land for wholesale transmission service within the United States'' is wrong; open access is not the law of the land for United States non-public utilities, since we have no section 205–206 jurisdiction over them.

[352] United States public utilities, of course, are separately required by Order No. 888 to have on file open access tariffs and thus meet reciprocity through the separate, more stringent open access requirement.

[353] Ontario Hydro also complains that the reciprocity obligation of domestic non-public utilities is subject to various limitations and waiver provisions. These provisions apply to foreign entities as well.

[354] In recent cases involving the mitigation of transmission market power of Canadian utilities that are affiliates of power marketers that seek to sell power at market-based rates in the United States, the Commission has explicitly acknowledged the sovereign authority of Canadian governments over Canadian entities and has said that we will be ''amenable to a variety of approaches'' for foreign utilities to mitigate

Continued

Ontario Hydro is also wrong in its claim that even aside from NAFTA, we lack authority under the FPA to require reciprocity when a foreign entity wishes to use a domestic utility's open access tariff. Just as we are not asserting jurisdiction over domestic non-public utilities under sections 205 or 206 of the FPA, we also are not asserting jurisdiction over foreign entities. Rather, we are simply placing the same reasonable and fair condition on both types of entities' uses of the transmission ordered in the Final Rule.[355]

Rehearing Requests

Unconstitutional as Applied to NE Public Power District

NE Public Power District asserts that the reciprocity provision as applied to NE Public Power District (a public corporation and political and governmental subdivision under Nebraska law) is unconstitutional. It argues that reciprocity would intrude into the sovereignty of Nebraska and would negate the decision of Nebraska's citizens to use their own governmental institutions to provide electric service. Moreover, contrary to the Commission's assertion, NE Public Power District states that it does not have a real choice in deciding whether to use the transmission service of public utilities. Because it is beyond the power of Congress to compel Nebraska to adopt a federally prescribed program for providing its citizens with electric utility services, NE Public Power District argues that it must follow that a federal agency lacks the constitutional and statutory authority to compel a Nebraska state instrumentality to adopt a FERC-drafted tariff and to modify its contracts.

NE Public Power District states that section 201(f) of the FPA exempts state-owned utilities from the jurisdiction of the Commission and that sections 211–213 are the exclusive means by which the Commission can require non-public utilities to perform involuntary transmission service. It asserts that the Commission should exempt publicly-owned utilities from application of the Final Rule and notes that virtually all non-public utility entities are, or soon will be, voluntary participants in power pools, RTGs, or other similar organizations. Thus, NE Public Power District argues that there is no compelling public interest to require these entities now to submit to the reciprocity provision.

In addition, NE Public Power District argues that compliance would conflict with Nebraska law and bond covenants, *i.e.,* Nebraska law, for example, does not permit a public entity to agree in advance of a dispute to submit to binding arbitration. NE Public Power District states that it is bound by a bond covenant that prohibits it from rendering service free of charge and requires that a customer's default must be cured within a specific time. It also argues that these requirements are in conflict with section 7.3 of the pro forma tariff.

Commission Conclusion

Under the Supremacy Clause of the Constitution, Nebraska law cannot and does not override this Commission's authorities and responsibilities under the FPA. Rather, this Commission has exclusive jurisdiction over the rates, terms and conditions of transmission in interstate commerce by public utilities, including reciprocity conditions contained in the tariffs of public utilities. Nothing in Order No. 888 compels Nebraska to adopt a ''federally prescribed program.'' While we do not have full jurisdiction over non-public utilities,[356] our actions in regulating jurisdictional matters may impact those who wish to use jurisdictional services or to enter into agreements with public utilities. The Commission's obligation is to ensure that public utilities' services are just and reasonable and not unduly discriminatory or preferential and non-public utilities can choose to comply or not regarding matters within our exclusive jurisdiction. Moreover, as we explained above, NE Public Power District can seek waiver of the reciprocity condition on a case-by-case basis.

Rehearing Requests

QF Position

American Forest & Paper asks the Commission to clarify that QFs are exempted from the reciprocity requirement or, in the alternative, grant them a blanket waiver. It states that QFs are not allowed to provide transmission service for third parties. Moreover, it asserts that there are unlikely to be many requests for transmission service over a QF's interconnection line and such cases should be handled on a case-by-case basis.

Commission Conclusion

We will not grant QFs an exemption from the reciprocity condition or grant them a blanket waiver, but will address this issue on a case-by-case basis if and when it arises. Because most QFs own little transmission, it is not likely that they will be asked to provide reciprocal service.

Furthermore, in a proceeding involving a QF, we explained that use of a QF's transmission line by a non-QF would not affect its QF status:

> It would not fail the ownership test for QF status because, consistent with the requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA), the Oxbow Geothermal facility would continue to be ''owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities).'' 16 U.S.C. § 796(18)(B)(1994).[357]

If a QF that owns, controls or operates interstate transmission facilities seeks open access transmission from a public utility, it must agree to provide reciprocal service to that public utility. Of course, the QF could file a waiver request in a separate proceeding, as set forth in the Final Rule and clarified in a subsequent order.[358]

Rehearing Requests

Tax-Exempt Financing Issues

Reciprocity and Private Activity Bonds

EEI asks the Commission to require non-public utilities claiming that their tax status is a bar to granting reciprocity to substantiate such claim in a safe harbor proceeding and to take reasonable measures to request the IRS to allow them to provide reciprocal service while retaining their tax status. If the Commission decides not to require a safe harbor proceeding, EEI requests that the Commission require non-public utilities to substantiate their tax concerns and to demonstrate to each public utility from which they seek service that they are actively pursuing

transmission market power. British Columbia Power Exchange Corporation, 78 FERC ¶61,024 (1997); *accord,* TransAlta Enterprises Corporation, 75 FERC ¶61,268 (1996) and Energy Alliance Partnership, 73 FERC ¶61,019 (1995).

[355] EEI and Ontario Hydro note that section 6 of the tariff limits the obligation of foreign utilities to provide reciprocal service to ''facilities used for transmission of electric energy in interstate commerce owned, controlled or operated by the Transmission Customer. . . .'' (EEI at 14). This is inconsistent with the preamble, which says that the reciprocity provision applies to foreign entities (whose transmission facilities may not be ''interstate''). We recognize that the language in section 6 of the pro forma tariff conflicts with the preamble language of the Final Rule. We are modifying section 6 of the tariff accordingly.

[356] We do have jurisdiction over many non-public utilities under certain sections of the FPA, *e.g.,* sections 210, 211 and 212.

[357] Oxbow Power Marketing, 76 FERC ¶ 61,031 at 61,179 (1996), *reh'g pending.* We did note, however, that the QF would become a public utility to the limited extent it provides transmission service over its line on behalf of others.

[358] *See* Order Clarifying Order Nos. 888 and 889 Compliance Matters, 76 FERC ¶ 61,009 at 61,027 (1996).

the issue with the IRS.[359] It also urges that the Commission require any request for exemption from the reciprocity requirement that is based on jeopardy to tax-exempt status be filed with the Commission as part of a request for declaratory order in a safe harbor proceeding. Moreover, it requests that the Commission require a non-public utility to specifically identify the facilities it cannot use without jeopardizing its tax-exempt financing and to provide copies of, and specifically reference the tax provisions in, the related financing agreements that embody this restriction.

Centerior asks that the Commission condition receipt of open access transmission service by municipal utilities upon the elimination or mitigation of tax subsidies and regulatory inequities. Southern maintains that tax-exempt status can remain undisturbed if non-public utilities do not seek open access transmission service from public utilities. Thus, Southern asserts, non-public utilities can weigh the benefits of transmission service under the Final Rule against the potential threat to their tax benefits, and make the choice that serves their best interest. At a minimum, it argues, the Commission should await the determinations of the IRS before finalizing this aspect of the reciprocity provision, rather than confer yet another unique benefit on non-public utilities.[360]

CAMU asks that the Commission defer reciprocity obligations until the IRS has clarified the status of private use limitations within the context of transmission access. Otherwise, CAMU asserts, innocent investors could suffer penalties because the Commission moved too quickly on this sensitive issue.

Local Furnishing Bonds

Local Furnishing Utilities and ConEd state that section 5.1 of the pro forma tariff applies to ''Transmission Service,'' which is defined in section 1.48 to include point-to-point service, but not network service. They ask the Commission to clarify that the phrase ''transmission service'' also applies to network service.

Local Furnishing Utilities and ConEd ask that the Commission confirm that all costs associated with the loss of tax-exempt status, including defeasing, redeeming, and refinancing tax-exempt bonds, will be considered costs of providing transmission that must be borne by the customer for whom the transmission is provided. They state that defeasance and refinancing costs are just as attributable to the particular transmission service causing such defeasance or redemption as the costs of expanding the system are attributable to the service that cause the need for such expansion. They ask that the Commission clarify that a transmission provider may include in its tariff a provision permitting the recovery of such costs, even if a filing under section 205 of the FPA is required. ConEd asserts that if a customer does not want to pay costs associated with the loss of tax-exempt status on the bonds, the Commission should allow the transmission provider to decline to provide the requested service.

Local Furnishing Utilities and ConEd also assert that section 5.2 of the pro forma tariff should be clarified to state that issuance of a section 211 order by the Commission is a condition precedent to the provision of transmission service. Local Furnishing Utilities states that there is a question whether the Commission should insist on waiver of the issuance of a proposed order under section 212(c). According to Local Furnishing Utilities, the negotiations that normally would follow the issuance of a proposed order are likely to provide the only opportunity to demonstrate and review the costs associated with the loss of tax-exempt status.

Local Furnishing Utilities and ConEd assert that sections 5.1 and 5.2(i) of the pro forma tariff improperly limit the safe harbor protection of section 1919 of EPAct to transmission providers that financed ''transmission facilities'' with local furnishing bonds. Because of this, they assert, the safe harbor is not available to ConEd, all of whose local furnishing bonds have been used to finance its distribution system. They argue that section 5.1 should apply to service that would jeopardize the tax-exempt status of bonds that finance distribution or generation, as well as transmission, facilities. NE Public Power District contends that section 5.2(ii) should be amended ''to make it clear that interim service need not be begun if rendering the service would endanger the tax-exempt status of the provider's bonds, unless the customer agrees to bear the financial consequences of such loss of tax-exempt status and has the wherewithal to do so.'' (NE Public Power District at 22–23).

SoCal Edison argues that local furnishing utilities should be required to comply with the Final Rule without any exception based upon their tax-exempt bonds.

Commission Conclusion

Private Activity Bonds

As we explained in Order No. 888, it is not our purpose to disturb Congress's and the IRS's determinations with respect to tax-exempt financing. With respect to private activity bonds, we reaffirm our finding that reciprocal service will not be required if providing such service would jeopardize the tax-exempt status of the transmission customer's (or its corporate affiliates') bonds used to finance such transmission facilities. We remain hopeful that the IRS in its private activity bond rulemaking will, to the maximum extent possible, remove regulatory impediments that limit the ability of industry participants to provide reciprocal open access. As we indicated in Order No. 888, after the IRS acts, we will reexamine our policy to ensure that the reciprocity condition is applied broadly to achieve open access without jeopardizing tax-exempt financing.[361]

We will reject the request of EEI and Tucson Power that the Commission require non-public utilities to substantiate in a safe harbor proceeding a claim that their tax status is a bar to granting reciprocity. As we stated in Order No. 888, if a non-public utility has sought a declaratory order on a voluntarily-filed tariff, we request that it identify the services, if any, that it cannot provide without jeopardizing the tax-exempt status of its financing. However, we cannot require that a non-public utility use the safe harbor mechanism, whether to file a reciprocal tariff with the Commission or to substantiate a claim as to loss of tax-exempt status. As we explain above, the safe harbor procedure is a voluntary means for non-public utilities to obtain a Commission determination that they meet the reciprocity condition in the open access tariffs and thereby avoid potential delays or denials of open access service based on allegations that the transmission requestor does not meet reciprocity.

Nevertheless, just as we believe that it is appropriate to condition the use of public utility open access tariffs on the

[359] *See also* Tucson Power.

[360] *See also* SoCal Edison. It asserts that the Commission should require publicly-owned utilities to provide open access on the same terms as other utilities after a short transitional period that provides an opportunity for the IRS and/or Congress to address the interrelationship between open access transmission and tax-exempt financing.

[361] We note that on January 10, 1997, the IRS issued final regulations on the definition of private-activity bonds applicable to tax-exempt bonds issued by state and local governments, but reserved section 1.141–7 dealing with output contracts to further consider the issues raised by regulatory changes in the electric power industry. 62 FR 2275 (January 16, 1997).

agreement of the tariff user to provide reciprocal access to the transmission provider, we also believe it is appropriate to condition the use of public utility open access tariffs on the agreement of the non-public utility tariff user to substantiate any claim that providing reciprocal transmission service would jeopardize the tax-exempt status of its financing. The non-public utility can provide such substantiation by identifying for the customer the services that it cannot provide without jeopardizing its tax-exempt financing.[362]

Southern suggests that tax-exempt status can remain undisturbed if non-public utilities do not seek open access transmission service from public utilities and, therefore, that non-public utilities can weigh the benefits of transmission service under the Rule against the potential threat to their tax benefits. We believe it is important to remember why we required open access in the first place—as a remedy for undue discrimination in transmission services in interstate commerce. Southern would force a non-public utility to give up a Congressionally-mandated right as a condition to taking open access transmission. Clearly Southern's suggestion is misplaced and overbroad.[363] For this reason, we believe that our decision not to require reciprocal service if providing such service would jeopardize the non-public utility's tax-exempt financing—pending action by the IRS in its private activity bond rulemaking—is appropriate for the time being.[364] We reiterate that we will reexamine our policy after the IRS acts. As we state above, we believe that ultimately the public interest is best served by nationwide open access.

Local Furnishing Bonds

We clarify, in response to Local Furnishing Utilities and ConEd, that the reference to ''Transmission Service'' in section 5.1 of the pro forma tariff was intended to be to ''transmission service,'' and thereby to apply to point-to-point service as well as network service. We have revised section 5.1 accordingly.

We further clarify that all costs associated with the loss of tax-exempt status, including the costs of defeasing, redeeming, and refinancing tax-exempt bonds, are properly considered costs of providing transmission services. Therefore, a customer that takes service, understanding that such service will result in loss of tax-exempt status, shall be responsible for such costs to the extent consistent with Commission policy, and a transmission provider may include in its tariff a provision permitting it to seek recovery of such costs. We clarify that if the transmission customer is not willing to pay the costs associated with the transmission provider's loss of tax-exempt status, the transmission provider will not be required to provide the requested service.[365]

Local Furnishing Utilities and ConEd also ask the Commission to revise section 5.2 of the pro forma tariff to state that issuance of a section 211 order by the Commission is a condition precedent to the provision of transmission service. Under the tariff provision adopted by Order No. 888 to address situations in which the provision of transmission service would jeopardize the tax-exempt status of any local furnishing bonds used to finance a local furnishing utility's facilities, the customer requesting transmission service would tender an application under section 211 of the FPA. Within ten days of receiving a copy of the section 211 application, the transmission provider ''will waive its rights to a request for service under Section 213(a) of the [FPA] and to the issuance of a proposed order under Section 212(c) of the [FPA] and shall provide the requested transmission service in accordance with the terms and conditions of this Tariff.''[366] We clarify that the Commission, upon receipt of the transmission provider's waiver of its rights to a request for service under section 213(a) and to the issuance of a proposed order under section 212(c), shall issue an order under section 211.[367] Upon issuance of the order under section 211, the transmission provider shall be required to provide the requested transmission service in accordance with the terms and conditions of the tariff. Section 5.2 of the pro forma tariff has been revised accordingly.

Local Furnishing Utilities and ConEd also contend that the language of sections 5.1 and 5.2(i) of the pro forma tariff improperly limits the safe harbor protection of section 1919 of EPAct to transmission providers that financed transmission facilities with local furnishing bonds. ConEd expresses concern that although all of its electric local furnishing bonds have been used to finance its distribution system, the test as to whether those bonds have been used for the ''local furnishing'' of electricity is based in part on whether ConEd has been a ''net importer'' of energy into its service territory. As a result, ConEd argues that the use of its transmission system to wheel power from a generating source located inside ConEd's service territory to a customer located outside its service territory could cause ConEd to violate the net importer rule and thereby lose the tax exemption for the bonds used to finance its distribution system. ConEd asks the Commission to modify sections 5.1 and 5.2 of the pro forma tariff to make clear that those provisions apply to transmission providers that have financed any ''facilities'' (*i.e.*, distribution and generation, not just transmission, facilities) with local furnishing bonds.

As we explained in Order No. 888, we believe the local furnishing bonds

[362] In response to EEI's request that the Commission require a non-public utility to provide copies of, and specifically reference the tax provisions in, the related financing agreements, we note that the level of detail needed to substantiate a non-public utility's claim that providing reciprocal transmission service would jeopardize the tax-exempt status of its financing is likely to depend on the facts of each case. As a result, what will constitute adequate substantiation is properly determined on a case-by-case basis. Additionally, we will reject EEI's request that the Commission require non-public utilities to demonstrate that they are actively pursuing the issue with the IRS. As we explain above, the IRS is currently examining these issues; we in turn will reexamine our policy after the IRS acts to ensure that the reciprocity condition is applied broadly to achieve open access without jeopardizing tax-exempt financing.

[363] We will reject Centerior's request that the Commission condition receipt of open access transmission service by non-public utilities upon the elimination or mitigation of tax subsidies. As we stated in Order No. 888, Congress has entrusted the IRS with the responsibility for implementing laws governing tax-exempt financing, and it is not this Commission's purpose to disturb Congress's and the IRS's determinations in that regard.

[364] In response to CAMU, we note that the Commission has, in effect, deferred—pending IRS action—a non-public utility's reciprocity obligation in cases in which the provision of reciprocal service would jeopardize the tax-exempt status of the non-public utility's financing.

[365] Of course if the transmission provider can provide part of the requested service without jeopardizing tax-exempt status, it should offer to provide such service.

[366] Pro Forma Open Access Transmission Tariff, Section 5.2(ii).

[367] We will reject Local Furnishing Utilities' request that the Commission reconsider whether it should insist on the transmission provider's waiver of the issuance of a proposed order under section 212(c). As Order No. 888 indicates, this aspect of the local furnishing provision of the tariff is similar to a provision included in the transmission tariff of San Diego G&E, one of the Local Furnishing Utilities. Waiver of the issuance of a proposed order enables a transmission provider to expeditiously provide service under section 5.2 of the pro forma tariff, thereby ensuring that any local furnishing bonds that may exist do not interfere with the effective operation of an open access transmission regime. Although Local Furnishing Utilities now apparently support the issuance of a proposed order on the basis that the negotiations that normally would follow are likely to provide an opportunity to review the costs associated with the loss of tax-exempt status, we believe that any dispute as to costs subsequently can be resolved without causing any delay in the provision of the requested transmission service. For example, the service could be provided at the maximum rate allowed by the Commission, subject to refund.

provision in section 5 of the pro forma tariff is necessary and appropriate so that any local furnishing bonds that may exist do not interfere with the effective operation of an open access transmission regime. If the provision of transmission service pursuant to Order No. 888 would result in the loss of tax-exempt status for local furnishing bonds, regardless of whether the facilities financed with those bonds are transmission, distribution, or generation facilities, it is our intent that the provisions of section 5 would apply. Thus, we clarify in response to ConEd and Local Furnishing Utilities that, to the extent the provision of transmission under an open access tariff would jeopardize the tax-exempt status of local furnishing bonds used to finance distribution or generation facilities (even if no transmission facilities were financed with such bonds),[368] such situation would fall within the reference to ''facilities that would be used in providing . . . transmission service'' contained in sections 5.1 and 5.2(i). This is so because the loss of tax-exempt status in such circumstances would be directly attributable to the provision of transmission services under the Rule.

Further, we said in Order No. 888 that ''we will require any public utility that is subject to the Open Access Rule that has financed transmission facilities with local furnishing bonds to include in its tariff'' a provision similar to section 5 of the pro forma tariff.[369] We clarify that we did not intend by this statement that the section 5 local furnishing bonds provision would only apply to public utilities that have financed transmission facilities with local furnishing bonds, and not those that have financed generation and distribution facilities with such bonds. As we explain above, it is our intent that the provisions of section 5 apply if the provision of transmission service pursuant to an open access tariff would result in the loss of tax-exempt status for local furnishing bonds, regardless of whether the facilities financed with those bonds are transmission, distribution, or generation facilities.

Rehearing Requests

Unfunded Mandates Reform Act

NE Public Power District[370] argues that the final regulations adopted in this proceeding ''constitute[] an unfunded mandate under the Unfunded Mandates Reform Act of 1995 * * *.''[371] It declares that Order No. 888 imposes significant costs upon local governments and that the Commission was required under the Unfunded Mandates Reform Act to consider the financial impact of its rulemaking upon state and local governments and to prepare and issue as part of its rulemaking process a statement containing certain specified analyses and estimates concerning this matter and a description of its pre-issuance consultations with state and local government authorities. To support its argument NE Public Power District relies upon: (a) Executive Order No. 12875, *Enhancing the Intergovernmental Partnership* (Executive Order);[372] and (b) the Unfunded Mandates Reform Act of 1995 (the Act).[373]

Commission Conclusion

We disagree with NE Public Power District. The Executive Order applies to every ''executive department * * * [and] agency. * * * ''[374] It defines ''executive agency'' as ''any authority of the United States that is an 'agency' under 44 U.S.C. § 3502(1), *other than those considered to be independent regulatory agencies, as defined in 44 U.S.C. § 3502 (10).*''[375] In section 3502(10), the Federal Energy Regulatory Commission is defined as an independent regulatory agency. As a result, the Executive Order does not apply to the Commission.

The Act similarly applies to federal agencies, but, as with the Executive Order, does not apply to independent regulatory agencies.[376] Although the Act does not define ''independent regulatory agency,'' there is no indication that Congress intended to exclude the Commission from the definition. In fact, in all instances in which Congress has defined the term ''independent regulatory agency'' of which we are aware, the Commission has been included.

As noted, the Commission is defined as an independent regulatory agency in Title 44 U.S.C. Also, Title 42 U.S.C. § 7176 provides that:

> For the purposes of chapter 9 of title 5, United States Code * * * [Executive Reorganization], the [Federal Energy Regulatory] Commission shall be deemed to be an independent regulatory agency.[377]

Accordingly, we find that the Commission is an independent regulatory agency as used in the Act; therefore, it is not covered by the Act.

Moreover, even if the Act applied to the Commission, the Final Rule will not impose a Federal mandate on state, local or tribal governments.

Section 305 of the Act defines a ''Federal mandate'' as:

> any provision in [a] statute or regulation or [in] any Federal court ruling that *imposes an enforceable duty* upon State, local, or tribal governments[,] including a condition of Federal assistance or a duty arising from participation in a voluntary Federal program.[378]

The Open Access Final Rule imposes requirements only on certain public utilities[379] and, pursuant to section 201(f) of the FPA, state and local

[368] ConEd suggests that this might occur if, for example, the provision by ConEd of transmission service were to cause it to violate the net importer rule and thereby lose the tax exemption for bonds used to finance its local distribution system. Although we clarify above that section 5 of the pro forma tariff would apply to this situation, we note that it is not clear that wheeling required by the Commission would be counted for purposes of determining whether a public utility is a ''net importer.'' In its committee report on the bill that became the Energy Policy Act, the House Ways and Means Committee stated:

> The committee believes further that, in applying the IRS ruling position that a local furnishing utility that is interconnected with other utilities (other than for emergency transfers of electricity) must be a net importer of electricity, the determination of whether the utility is a net importer should be made without regard to electricity generated by another party that is wheeled by the utility to a point outside its service area pursuant to a FERC order authorized under the bill.

H.R. Rep. No. 102–474(VI), 102d Cong., 2d Sess. 25 (1992), *reprinted in* 1992 U.S.C.C.A.N. 2232, 2236.

[369] FERC Stats. & Regs. at 31,763; *mimeo* at 377.

[370] NE Public Power District is a public corporation and a political subdivision of the State of Nebraska that generates, transmits and delivers electric energy to wholesale and retail customers throughout the state.

[371] NE Public Power District at 2. NE Public Power District asserts that the Commission failed to respond to this issue as raised by NE Public Power District in its comments.

[372] Executive Order No. 12875, 3 CFR 699–71 (1994); 58 Fed. Reg. 58,093–094 (1993). The Executive Order provides that, unless required by statute, no Executive department or agency shall promulgate any regulation that creates a mandate upon state, local or tribal governments unless it either: (a) provides the funds necessary to carry out the obligations; or (b) before promulgating the regulation, provides to the Director of the Office of Management and Budget: (1) a description of its consultation with the affected governments; (2) a statement of their concerns and copies of communications it has received from them; and (3) the reasons why it thinks the regulations should issue.

[373] The Unfunded Mandates Reform Act is Pub. L. No. 104–4, 109 Stat. 48 (1995) (to be codified at 2 U.S.C. §§ 602, 632, 653, 658, 1501–1504, 1511–1516, 1531–1538, 1551–1556 and 1571).

[374] 3 CFR at 670; 58 FR 58093 (1993).

[375] 3 CFR at 671; 58 FR at 58094 (1993) (emphasis supplied).

[376] 90 Stat 50 (to be codified at 2 U.S.C. § 658).

[377] 42 U.S.C.A. § 7176 (1995) (Department of Energy Organization Act) (P.L. 95–91, 91 Stat. 586) (1977). *See also* Pub. L. No. 104–13, the Paperwork Reduction Act of 1995 § 3502(5), 109 Stat. 165 (1995) (to be codified at 44 U.S.C. § 3502(5)), which provides that ''the term 'independent regulatory agency' means [among other agencies] * * * the Federal Energy Regulatory Commission.''

[378] 109 Stat. 70 (to be codified at 2 U.S.C. § 1555) (emphasis supplied).

[379] *I.e.*, those that own, operate or control interstate transmission facilities and do not obtain a waiver from the Commission.

governments, and their agencies, authorities and instrumentalities, are not public utilities. Additionally, although the Final Rule will allow public utilities' transmission tariffs to contain reciprocity provisions in order to ensure that public utilities offering open access transmission to others can obtain similar service from open access users, the reciprocity provision is not an *enforceable duty.* A duty is mandatory; it is an obligation to perform and is compulsory.[380] The reciprocity provision is merely a condition of receiving a benefit, *i.e.*, open access transmission service from a public utility.[381] There is no requirement that NE Public Power District promulgate an open access tariff and apply to FERC for a declaratory order. Moreover, as we explained above, non-public utilities, such as NE Public Power District, are free to seek from a public utility a waiver of the open access tariff reciprocity condition.

With regard to the Stranded Cost Final Rule, while it applies to non-public utilities as well as public utilities, it does not impose a duty on any entity since it merely permits public utilities and transmitting utilities to seek recovery of certain costs. As a result, since the Open Access and Stranded Cost final rules will not impose an enforceable duty on state, municipal or tribal power agencies such as NE Public Power District, the rules are not Federal mandates as defined in the Act.

Because the Unfunded Mandates Reform Act of 1995 does not apply to the Commission and, in any event, the Open Access/Stranded Cost final rules do not impose Federal mandates on state, local or tribal governments, we reject NE Public Power District's argument that the Unfunded Mandates Reform Act of 1995 is applicable here.

5. Liability and Indemnification

In the Final Rule, the Commission explained that the indemnification provision was broken into two parts (set forth in section 10.1 (Force Majeure) and section 10.2 (Indemnification) of the pro forma tariff).[382] The Commission explained that the first part is a force majeure provision which provides that neither the transmission provider nor the customer will be in default if a force majeure event occurs, but also provides that both the transmission provider and customer will take all reasonable steps to comply with the tariff despite the occurrence of a force majeure event.

The Commission explained that the second portion of the provision provides for indemnification against third party claims arising from the performance of obligations under the tariff. The Commission limited the indemnification portion of the provision so that it is only the transmission customer who indemnifies the transmission provider from the claims of third parties. The Commission explained that 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.

Rehearing Requests

A number of utilities argue that the Commission has expanded transmitter liability beyond the existing standard in the industry, *i.e.*, gross negligence.[383] They assert that the Commission has provided no basis to subject transmission providers to liability, including consequential damages, due to ordinary negligence. KCPL points out that 21 of 25 states addressing this issue hold that a utility should not be liable for ordinary negligence. It declares that society will be worse off in litigation expenses and wasted human resources if utilities are held liable for simple negligence. It adds that the electric industry is much more susceptible to liability from interruptions of service than gas pipelines (refuting the Commission's reliance on *Pacific Interstate Offshore Company*, which it states is traceable to *United Gas Pipeline Co.* v. *FERC*, 824 F.2d 417 (5th Cir. 1987)). Florida Power Corp asks the Commission to modify section 10.2 to provide that a customer must indemnify the transmission provider except where a finder of fact determines that the transmission provider has committed gross or intentional wrongdoing. It also argues that the Commission should eliminate liability of both the transmission provider and the customer to the other for consequential damages.

Southern argues that the exception language in section 10.2 should be changed to ''except where a court has determined that the Transmission Provider has engaged in intentional wrongdoing or has been grossly negligent.'' (Southern at 20–21). Southern also argues that the Commission should limit consequential damages arising from negligence in the operation of the transmission system.

Puget asserts that the exception language in section 10.2 should be changed to ''except in cases of and to the extent of comparative or contributory negligence or intentional wrongdoing by the Transmission Provider.'' (Puget at 18). It also asserts that the Commission should exclude liability for special, incidental, consequential, or indirect damages.

EEI argues that the Commission should add a new section 10.3: ''If the Transmission Provider is found liable for any damages associated with this Tariff, those damages shall be limited to direct damages, and the Transmission Provider shall not be liable for any special, indirect or consequential damages of any nature by virtue of the transactions conducted under this Tariff.'' (EEI at 26).

Coalition for Economic Competition argues that the Commission should modify section 10.2 to provide that the transmission provider will not be liable to a transmission customer or any third party for damages caused by interruptions or irregular or defective service, except if gross negligence or wilful misconduct caused such damages.[384] Coalition for Economic Competition asserts that the definition of force majeure should include ordinary negligence and asks that the Commission clarify that a utility is not liable for force majeure events.

CCEM also argues that transmission customer indemnity in section 10.2 should attach only to legal actions brought by customers of the transmission customer or third-party beneficiaries of those customers.

On the other hand, TDU Systems argues that the indemnity provision unfairly provides the transmission provider with virtually total indemnification for acts on its side of the delivery point, but provides no reciprocal protection to the transmission customers for damage incurred on the customers' system in connection with purchasing the transmission provider's services.

[380] Dayton Hudson Corp. v. Eldridge, 742 S.W. 2d 482, 485–86 (1987); Kerrigan v. Errett, 256 N.W. 2d 394, 399 (1977); Huey v. King, 415 S.W. 2d 136, 138 (1967); Black's Law Dictionary 505 (6th ed. 1990).

[381] A state or municipal power authority, such as NE Public Power District, does not have to agree to reciprocity, and the Commission cannot force it to do so. The Commission is not requiring state or municipal power authorities to provide transmission access. If non-public utilities elect not to take advantage of open access services because they don't want to meet the tariff reciprocity provision, they can still seek voluntary, bilateral transmission service from public utilities.

[382] FERC Stats. & Regs. at 31,765–66; *mimeo* at 384–85.

[383] Coalition for Economic Competition, EEI, KCPL, Florida Power Corp.

[384] *See also* EEI at 26 (suggesting ''except in cases of a finding by a trier of fact of gross negligence or intentional wrongdoing by the Transmission Provider'').

CSW Operating Companies asks the Commission to revise the pro forma tariff to provide that a transmission provider will not be liable for errors in an estimate made in good faith and in accordance with its published procedure. They propose the following language:

Information posted on the OASIS concerning the availability of transfer capability will be based on the Transmission Provider's best estimates given the information readily and actually available to the transmission provider. No such estimate will be binding on the Transmission Provider for any purpose.

Alternatively, they ask the Commission to clarify that as long as a transmission provider in good faith follows its published methodology for determining ATC and TTC it will be deemed not to be negligent.

Commission Conclusion

The purpose of the force majeure provision in the pro forma tariff is to ensure that neither the customer nor the transmission provider is held in default in the event of an unpredictable and uncontrollable force majeure event. It was not the Commission's intention that the force majeure clause provide an avenue for a party to claim that it is excused from liability for its own negligence. A force majeure event does not include an act of negligence or intentional wrongdoing. The pro forma tariff will be changed accordingly.[385]

The purpose of the indemnification provision is to allocate the risks of a transaction, and the costs associated with those risks, to the party on whose behalf the transaction has been conducted, the transmission customer. As the tariff does not obligate the customer to perform services on behalf of the transmission provider, there is no comparable basis for imposing an indemnification obligation on the transmission provider.[386]

As is explained in the Final Rule, the Commission does not believe it appropriate to extend the indemnification obligation so that it would apply even in cases where the transmission provider has been negligent. The contention that electric transmission outages are either more frequent or more costly than gas outages does not serve to distinguish the electric transmission situation from the gas pipeline cases in which the Commission has found that indemnification clauses should not protect the pipeline owner from its own negligence.[387] In either case, it would be inappropriate to require the customer to indemnify the transmission provider from damages arising from the transmission provider's own negligence. We note, however, that liability is a separate issue from indemnification. Despite the absence of indemnification protection, there is nothing in the indemnification provision that would preclude transmission providers from relying on the protection of state laws, when and where applicable, protecting utilities or others from claims founded in ordinary negligence.

With respect to the issue of consequential and indirect damages, the indemnification provision already provides protection to the transmission provider from consequential and indirect damage claims by third parties except in cases of negligence or intentional wrongdoing by the transmission provider. The Commission sees no need to further extend this protection. Again, we note that liability is a separate issue from indemnification, and that nothing in these provisions precludes transmission providers or customers from relying, when and where such law is applicable, on the protection of statutes or other law protecting parties from consequential or indirect damages.

Furthermore, we will not revise the pro forma tariff, as requested by CSW Operating Companies, to provide that a transmission provider will not be liable for errors in an estimate made in good faith or in accordance with its published procedure. We believe that a utility should have no different a liability standard for operating an OASIS than for its other operations.[388]

6. Umbrella Service Agreements

The Commission received requests for clarification regarding this issue, which was not specifically addressed by the Commission in the Final Rule.

Rehearing Requests

SoCal Edison argues that it is too burdensome to require a separate Completed Application and a separate Service Agreement to be executed for each individual service transaction for short-term firm and non-firm transmission service (and filed with the Commission). SoCal Edison contends that requiring a separate service agreement for each short-term firm transaction to be filed with the Commission will stifle transactions in the short-term market. It indicates that it suggested a simpler approach in Docket No. ER96–222–000 that would establish a non-transaction specific Service Agreement and a Completed Application that would contain the specific transaction information, but would not be filed with the Commission, but would be made available for audit.[389]

Commission Conclusion

SoCal Edison misinterprets the tariff provisions regarding service agreements for non-firm point-to-point transmission service. Tariff section 14.5 details the treatment of service agreements for non-firm transmission service:

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. (Emphasis added)

Moreover, in tariff section 18 (Procedures for Arranging for Non-Firm Point-To-Point Transmission Service) requires that a separate service agreement be executed for each individual service transaction as claimed by SoCal Edison. In the pro forma tariff, the Commission established a non-transaction specific (or ''umbrella'') service agreement in an attempt to streamline the application procedures for non-firm point-to-point transmission service. Therefore, the service agreement for non-firm point-to-point transmission service need only be executed and filed with the Commission once, when the transmission customer first applies for non-firm point-to-point transmission service. Subsequent non-firm transactions by the same customer only require the submission of a completed application (as provided in tariff sections 18.1 and 18.2) by that customer, which will be submitted via the transmission provider's OASIS (when the OASIS is fully implemented). Accordingly, no changes are required to

[385] *See Tex-La Electric Cooperative of Texas, Inc.*, 69 FERC ¶ 61,269 (1994) (requiring clarification that force majeure clause in electric transmission agreement does not excuse negligence); *Avoca Natural Gas Storage*, 68 FERC ¶ 61,045 (1994) (requiring modification of force majeure provision to ensure that parties would be liable for negligence or intentional wrongdoing).

[386] The Commission notes that in the past it may have accepted agreements containing gross negligence in force majeure and indemnification provisions. Consistent with the Commission's general policy of not abrogating existing contracts, we leave those provisions undisturbed.

[387] *See, e.g., Pacific Interstate Offshore Company*, 62 FERC ¶ 61,260 at 62,733–734 (1993) (requiring amendment of indemnification provisions that required indemnification except in cases of ''gross negligence'').

[388] *See, e.g.*, Texas Eastern Transmission Corporation, 62 FERC ¶ 61,015 at 61,107 (1993).

[389] To date, the Commission has only issued a suspension order in this proceeding.

the application procedures for non-firm point-to-point service.

However, we do find SoCal Edison's arguments persuasive that streamlined procedures should also be applied to applications for firm point-to-point transmission service with a duration of less than one year (short-term firm). We agree that there is no compelling reason to require the submission of separate service agreements for every short-term firm transaction. Accordingly, we will adopt an ''umbrella'' service agreement approach (as is currently used for non-firm point-to-point transactions) and require a service agreement of general applicability to be filed with the Commission when the first short-term firm transaction is arranged between the transmission provider and customer.

In order to facilitate an umbrella service agreement approach for short-term firm transmission service, minor modifications have been made to several sections of the pro forma tariff[390] as well as to Attachment A (Form of Service Agreement For Firm Point-To-Point Transmission Service). Notably, pages 3 and 4 of the service agreement, containing transaction specific information, is now required only for long-term firm point-to-point transmission service.

7. Other Tariff Provisions

a. Minimum and Maximum Service Periods

In the Final Rule, the Commission adopted a one-day minimum term for firm point-to-point service.[391] The Commission also concluded that it will not specify a maximum term for either firm point-to-point or network transmission service. However, the Commission modified the tariff to require that an application for transmission service specify the length of service being requested.

Rehearing Requests

CCEM states that a competitive market for hourly trades should be allowed to develop (transmission and ancillary services). It argues that contrary to the Commission's goal of comparability, the Rule effectively allows only incumbent utilities to participate in hourly markets on behalf of their own or network loads (citing section 13.1 of the pro forma tariff).

American Forest & Paper argues that firm and non-firm service should be made available on an hourly basis and that the Commission should assure that utilities make non-firm service available.

Commission Conclusion

It is unclear as to what hourly ''trades'' CCEM is referring. If CCEM is referring to off-system *sales*, the transmission provider is obligated to take transmission for any off-system sales under point-to-point transmission service under its tariff. Inasmuch as the tariff does not require the provision of hourly firm transmission, in order to provide itself with hourly firm transmission, the transmission provider would either: (1) reserve firm point-to-point service on a daily basis in order to participate in the hourly market or (2) propose in a section 205 filing to modify its tariff to voluntarily provide hourly firm point-to-point service. Under either circumstance, comparability would be maintained as all point-to-point customers would have equal access to the hourly market.

If CCEM is referring to *purchases*, hourly economy purchases by the transmission provider on behalf of its native load customers are also available on a comparable basis to network customers. However, if CCEM is referring to specific purchases made on behalf of a particular wholesale customer, this resale must be provided under point-to-point transmission service, as described above.

The Commission has rejected hourly firm point-to-point transmission service as a mandatory service to be provided under the Tariff.[392] Many entities would not oppose hourly firm service if afforded a lower priority, *i.e.*, if they were curtailed before longer-term firm services. However, with this lower priority there may be little or no difference between the pro forma tariff non-firm service and curtailable firm hourly service. The Commission adopted the one-day minimum term for firm service to address concerns that customers would engage in ''cream skimming'' by taking firm service only during the hours at the daily peak while taking non-firm service for other hours, and thereby avoiding paying a fair share of the costs of the transmission system. However, this does not mean that the Commission would not allow such services if voluntarily proposed by a transmission provider.

Finally, in response to American Forest & Paper, the transmission provider has every incentive to make non-firm service available to all eligible customers in order to benefit native load customers, as the revenues generated by this service are typically used as a revenue credit to offset the costs of providing firm service. In addition, parties may raise concerns with the Commission in a section 206 complaint if the transmission provider offers non-firm transmission service in a non-comparable, *i.e.*, unduly discriminatory fashion.

b. Amount of Designated Network Resources

In the Final Rule, the Commission indicated that it will not change the limitation on the amount of resources a network customer may designate.[393] The Commission explained that a transmission provider is required to designate its resources and is subject to the same limitations required of any other network customer.

The Commission further explained that limiting the amount of resources to those that the customer owns or commits to purchase will protect a utility from having to incur costs that are out of proportion to the customer's load.

With respect to the allocation of interface capacity under network service, the Commission clarified that a customer is not limited to a load ratio percentage of available transmission capacity at every interface. It explained that a customer may designate a single interface or any combination of interface capacity to serve its entire load, provided that the designation does not exceed its total load.

Rehearing Requests

A number of entities state that section 30.8 of the pro forma tariff should be clarified to conform to the Final Rule preamble. The preamble states that a network customer should not be limited to a load ratio percentage of available transmission capacity at every interface, but may designate a single interface or any combination of interface capacity to serve its entire load, provided that the designation does not exceed its total load. However, they point out that section 30.8 of the pro forma tariff provides that 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 ratio share.[394]

TAPS and Wisconsin Municipals ask the Commission to clarify the inconsistency by deleting the phrase ''Ratio Share'' at the end of the section 30.8. TAPS argues that section 30.8 of

[390] *See* changes to tariff sections 1.33, 1.34, 13.4, 13.7 and 17.3.

[391] FERC Stats. & Regs. at 31,752–53; *mimeo* at 346–47.

[392] FERC Stats. & Regs. at 31,752; *mimeo* at 346.

[393] FERC Stats. & Regs. at 31,753–54; *mimeo* at 349–50.

[394] *E.g.*, NRECA, Blue Ridge, TDU Systems, Cleveland, AEC & SMEPA, Wisconsin Municipals, TAPS.

the tariff conflicts with the preamble, other sections of the tariff itself (*see* section 28), and recent Commission orders (*Wisconsin Public Service Corporation,* 74 FERC ¶ 61,022 at 61,064 and *FMPA* v. *FPL,* 67 FERC 61,167 at 61,484). It further argues that load ratio restrictions on total interface usage would expand the market power of transmission providers.

EEI and Southern state that under section 30.8 and the related preamble language, it is unclear how the concept of load ratio share should be applied in the context of interface capacity, (*i.e.*, is the network customer entitled to a load ratio share of available transmission capacity or total transmission capacity for an interface?). They argue that ATC is the appropriate basis for calculating shares of interface capacity and state that the Commission should specify that network service entitles the user to a load ratio share of the available capacity of each interface. EEI adds that if sufficient interface capacity is available, a request by a network customer to use available interface capacity to bring in resources for network load in excess of its load ratio share of the interface should be accommodated under the point-to-point tariff and treated on a first-come, first-served basis.[395]

Florida Power Corp states that ''[i]n order to clarify that network customers may obtain transmission service over the transmission provider's interfaces in excess of their load ratio shares, the Commission should clarify that additional interface capability may be purchased (subject to availability) as firm point-to-point transmission service.'' (Florida Power Corp at 29).

Commission Conclusion

We agree that the pro forma tariff should be conformed to the preamble language in the Final Rule so that the interface capacity is limited to the customer's total load, not a load ratio share. This is consistent with the Commission's recent rehearing order in *FMPA* v. *FPL:*

We clarify that the phrase ''that is, up to its share of the load, 3%'' was not intended to limit FMPA's use of each interface to a discrete ratio (3%). Rather, FMPA, as well as Florida Power, can use each interface, if capacity is available, to service its entire network load. If the interface is [constrained] [sic], they will either pay redispatch costs or expansion costs based on their load ratio share.[396]

c. Eligibility Requirements

In the Final Rule, the Commission found that a non-discriminatory open access transmission tariff must be made available, at a minimum, to any entity that can request transmission services under section 211 and to foreign entities. [397]

Rehearing Requests

VT DPS and Valero state that the Final Rule does not appear to contemplate that marketers will buy network service or that one network service customer might serve a portion of the requirements of another network customer. Thus, they argue that network load can be double counted. To resolve this problem, they argue, service should be made available to suppliers rather than load, as provided in the NorAm NIS tariff, Section 1.5.

Commission Conclusion

Power marketers are specifically named in the definition of Eligible Customer (Section 1.11), and nothing in the Network Integration Transmission Service prohibits marketers from serving customers and designating those customers' loads (or portions thereof) as the marketers' Network Loads.

Additional rehearing requests regarding eligibility are addressed in Section IV.C.1. (Eligibility to Receive Non-discriminatory Open Access Transmission).

d. Two-Year Notice of Termination Provision

In the Final Rule, the Commission deleted the notice of termination provision from the tariff.[398]

Rehearing Requests

No requests for rehearing addressed this matter.

e. Termination of Service for Failure to Pay Bill

In the Final Rule, the Commission stated that section 7.3 of the Final Rule pro forma tariff provides that in the event of a customer default, the transmission provider may, in accordance with Commission policy, file and initiate a proceeding with the Commission to terminate service.[399]

Rehearing Requests

El Paso asserts that the Commission does not have the authority to prohibit a transmission provider from terminating service to a customer that has failed to pay its bill until permission from the Commission has been obtained. It argues that the Commission does not have abandonment authority under the FPA.

Commission Conclusion

El Paso is not correct. Under section 205 of the FPA, public utilities are allowed to effectuate changes in rates, charges, classification or service only after providing 60 days notice to the Commission and the public. Because a termination of service is clearly a change in service, public utilities must file notice of a termination 60 days prior to the proposed effective date.

In *Portland General Electric Company,* 75 FERC ¶ 61,310, *reh'g denied,* 77 FERC ¶ 61,171 (1996), we denied a requested waiver of section 35.15 of the Commission's Rules of Practice and Procedure to permit the utility to terminate service in the event of customer default. We indicated that we had previously explained the reasons for requiring public utilities to file notices of termination when seeking to discontinue service [400] and further explained that

electricity is not just any commercial good or service. Rather, Congress in the Federal Power Act has charged us with ensuring that sales for resale or transmission of electricity in interstate commerce by public utilities take place at rates, terms and conditions that are just and reasonable.[401]

f. Definition of Native Load Customers

The Commission defined the term ''Native Load Customers'' in section 1.19 of the pro forma tariff as:

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.

Rehearing Requests

The pro forma tariff defines native load customers as ''[t]he wholesale and retail power customers of the Transmission Provider. * * *'' Cooperative Power argues that the definition of native load customers should recognize that joint planning is a sufficient criterion, and that construction and operation by the

[395] TAPS filed a response opposing these requests for rehearing. (TAPS Response). As we explained above, we will accept the TAPS Response.

[396] 74 FERC at 61,018.

[397] FERC Stats. & Regs. at 31,754; *mimeo* at 351.

[398] FERC Stats. & Regs. at 31,754–55; *mimeo* at 353.

[399] FERC Stats. & Regs. at 31,794; *mimeo* at 467.

[400] E.g., to protect wholesale purchasers—and, by extension, ultimate consumers—from losing service unjustly; to provide the Commission an opportunity to ensure that the termination is just and reasonable. 77 FERC at 61,171.

[401] Id.

transmission provider should not be necessary for native load status to be conferred. It asserts that under joint planning, the loads of transmission-only customers are considered native, therefore the Commission should eliminate the word power from the definition.[402]

NRECA and TDU Systems state that traditional wholesale customers that have long been on the system, have assisted in paying for past expansions, and will likely continue to be captive to a provider's monopoly transmission service, should have ''native load equivalent'' rights if they take network or long-term firm service. If the transmission provider has planned and will plan in the future for a customer's full or partial needs, they argue that the customer should be treated as the equivalent of native load. They point out that section 1.19 of the tariff limits native load status only to wholesale *power* customers of the transmission provider.

VA Com argues that the definition of native load in section 1.19 of the tariff should include existing distribution cooperatives and others who currently provide service to end users.

Commission Conclusion

We reject Cooperative Power's suggestion to include transmission-only point-to-point customers in the definition of native load. We note that network customers are provided with rights comparable to native load customers because the transmission provider includes their network resources and loads in its long-term planning horizon. However, a point-to-point transmission service customer is not similarly situated to native load and Network Customers. The Network service formula rate requires the Network customer to pay a load-ratio share of the costs of the transmission provider's transmission system on an ongoing basis, while a point-to-point transmission service customer is only responsible for paying on a contract demand basis over the contract term. The network customer and the native load of the transmission provider pay all the residual costs of the transmission system and face greater risks of rate fluctuations due to facility additions and variations in load of both its and other customers. In contrast, the point-to-point transmission service customer may be more transitory in nature electing shorter terms of service and specific forms of service tailored for discrete services over specific time periods that do not necessarily enter into the transmission provider's planning horizon. To the extent a transmission customer desires similar rights and cost responsibilities to a native load customer, it can always elect to take network service.

We further note that, in granting a right of first refusal to existing customers, we afforded existing transmission only point-to-point customers a priority to continue to use the transmission provider's system.

VA Com's proposed change to the definition of native load was made in conjunction with its proposed change in the reservation priority (highest priority for ''native load'', followed by firm contract customers and lastly, non-firm customers). Because we are rejecting VA Com's proposed reservation priority (*see* Section IV.G.3.a. above), we will also reject its proposed conforming change to the definition of native load as proposed by VA Com.

g. Off-System Sales

Regarding the unbundling of off-system sales, the Final Rule required that all bilateral economy energy coordination contracts executed before the effective date of Order No. 888 must be modified to require unbundling of any economy energy transaction occurring after December 31, 1996.[403] Concerning the treatment of revenues from transmission associated with off-system sales, the Commission stated in the Final Rule that revenue from non-firm services should continue to be reflected as a revenue credit in the derivation of firm transmission tariff rates.[404]

Rehearing Requests

Montana Power asserts that the Commission should clarify that off-system sales that originate from generating plants or power purchases outside the transmission provider's system and do not use the transmission provider's transmission system should not be automatically assessed point-to-point charges.

Maine Public Service asks the Commission to clarify that revenues from off-system sales are not to be credited where the sales do not use the transmission provider's system (referencing sections 1.44 and 8.1 of the pro forma tariff). Maine Public Service states that it makes sales from Maine Yankee (which is not located on Maine Public Service's system) to customers not on its system and that it should not have to credit these sales revenues to its transmission customers.

Wisconsin Municipals asks the Commission to clarify that the provision and level of revenue credits are rate issues and that if parties have negotiated provisions for revenue credits, the Final Rule cannot be used to avoid obligations undertaken in a settlement.

Commission Conclusion

Utilities must take all transmission services for wholesale sales under new requirements contracts and new coordination services under the same tariff used by eligible customers. The Commission provided an extension until December 31, 1996, for utilities to take transmission service under the same tariff for their economy energy transactions, certain power pooling arrangements, and other multi-lateral arrangements.[405] The above criteria, however, only apply when a utility transmission system is being used to accommodate off-system sales. Therefore, a utility would not be required to take point-to-point transmission service if its transmission system is not being used for the transaction.

Maine Public Service's concern is misplaced. Maine Public Service states that certain of its sales do not use its own transmission system and that it pays other utilities for such transmission service. However, Section 8.1 only specifies the treatment of revenues the transmission provider receives from transmission service it provides itself when making third-party sales *using point-to-point transmission service under its tariff.* If Maine Public Service is not the transmission provider for these third-party sales, then Section 8.1 does not apply to such transactions.

Wisconsin Municipals' argument with respect to prior settlements has been previously addressed in Section IV.D.1.c.(2) (Energy Imbalance Bandwidth).

h. Requirements Agreements

A detailed description of the Commission's unbundling requirements pertaining to requirements agreements is described below.

Rehearing Requests

Blue Ridge requests that the Commission clarify the definitions of requirements, economy and non-economy energy coordination agreements. In addition, Blue Ridge

[402] Dairyland filed a supplemental request for rehearing raising similar arguments. (Dairyland Supplement). We will accept this pleading as a motion for reconsideration, not as a request for rehearing, because it was not filed within the 30-day statutory period for rehearing requests. *See* 16 U.S.C. § 8251(a).

[403] FERC Stats. & Regs. at 31,700; *mimeo* at 191.

[404] FERC Stats. & Regs. at 31,738; *mimeo* at 304.

[405] FERC Stats. & Regs. at 31,700; *mimeo* at 191.

seeks clarification regarding which dates are to be used to distinguish between existing and new contracts (July 11, 1994 or July 9, 1996).

Commission Conclusion

The definitions of economy and non-economy energy coordination agreements are addressed in section IV.F.4. (Bilateral Coordination Arrangements). With respect to Blue Ridge's concern regarding requirements agreements, we defined requirements contracts broadly in section 35.28(b)(1) of the Commission's regulations as ''any contract or rate schedule under which a public utility provides any portion of a customer's bundled wholesale power requirements.'' The definition is intended to encompass partial requirements service, since that service is intended to meet the bundled load requirements of a customer that is not provided from other sources such as self-generation or unit power purchases. In contrast, a non-economy energy coordination agreement is not intended to meet, by itself, the entirety of a customer's bundled power requirement or the residual partial power requirement of a customer. For example, a 50 MW unit power purchase or a long-term firm power purchase would supply long-term firm power but a customer would likely need an additional partial requirements agreement to supply the residual amount of its load requirement.

Regarding Blue Ridge's request for clarification of the dates for new and existing agreements, the Commission explicitly stated in Order No. 888 that any bilateral wholesale coordination agreements executed after July 9, 1996 would be subject to the functional unbundling and open access requirements set forth in the Rule.[406] In addition, the Commission required that all bilateral economy energy coordination contracts executed on or before July 9, 1996 be modified to require unbundling of any economy energy *transaction* occurring after December 31, 1996. The Commission permitted all non-economy energy bilateral coordination agreements executed before July 9, 1996 to continue in effect subject to section 206 complaints.

For the purpose of distinguishing between existing and new wholesale requirements contracts and for stranded investment recovery provisions, the Commission established July 11, 1994 as the applicable date.[407] For a utility to recover stranded investment costs in new requirements contracts, it must include explicit provisions in the contract for stranded investment recovery. *Existing* requirements contracts would not need a similar provision to be eligible for stranded investment recovery.[408] Utilities are required to unbundle all *new* requirements contracts. The requirement that utilities unbundle *existing* wholesale requirements contracts is for informational purposes and will enable existing requirements customers to evaluate and compare the transmission component of existing contracts to alternative contracts prior to the existing contracts' expiration dates.

i. Use of Distribution Facilities

The Commission received requests for clarification regarding this issue which was not specifically addressed by the Commission in the Final Rule.

Rehearing Requests

CSW Operating Companies asks the Commission to make clear that to the extent a transmission provider makes available to transmission customers the use of distribution facilities, the terms governing the use of and the charges for such use should be set forth in the customer's service agreement.

Commission Conclusion

Utilities are free to include customer-specific terms and conditions or terms and conditions limited to certain customers (*e.g.*, a distribution charge) in a customer's service agreement and/or the network customer's network operating agreement.

j. Losses

The Commission received requests for clarification regarding this issue which was not specifically addressed by the Commission in the Final Rule.

Rehearing Requests

VT DPS asserts that network customers should not have to bear losses twice—the tariffs allow collection of losses over all network load, even that supplied by behind the meter generation. It argues that losses should only be paid on power actually transmitted over the company's system.

Commission Conclusion

The pro forma tariff neither specifies the applicable Real Power Loss factors (see tariff section 28.5) nor the demand levels to which the loss factors should be applied. Accordingly, concerns regarding the loss calculation for a customer should be raised when the transmission provider files with the Commission a service agreement for a network customer.

k. Modification of Non-Rate Terms and Conditions

The Commission's requirements pertaining to modification of non-rate terms and conditions is described below.

Rehearing Requests

TAPS asserts that the language of section 35.28(c)(1)(v) and the preamble of Order No. 888 are inconsistent. TAPS argues that the Commission should require a demonstration of consistency with and superiority to the terms and conditions of the pro forma tariff and indicate that it will not allow deviations that seek to withdraw the minimum terms and conditions of non-discriminatory transmission. According to TAPS, the Commission should also clarify that the Commission will not let onerous tariff terms creep in through the back door, *i.e.*, through service agreements. TAPS also maintains that the Commission should not allow transmission providers to use conformity as an excuse to evade commitments.

Commission Conclusion

Order No. 888 allows a utility the flexibility to propose, after the compliance tariffs go into effect, to modify non-rate terms and conditions of the tariff if it can ''demonstrate[] that such terms * * * are consistent with, or superior to, those in the compliance tariff.'' These are the same principles that are referenced in the regulation language (deviations allowed if the transmission provider can demonstrate the deviation is consistent with the principles of Order No. 888). While utilities are free to file revised tariffs after their compliance filings, any filing including service agreements will be carefully reviewed by the Commission to assure that the revised tariffs and service agreements are just and reasonable and consistent with the principles of Order No. 888.

With regard to TAPS' concern about transmission providers evading commitments, we reiterate that we will not require abrogation of existing contracts (and the commitments reflected therein) except on a case-specific basis.

l. Miscellaneous Tariff Modifications

(1) Ancillary Services

The Commission explained that the pro forma tariff incorporates conforming revisions consistent with the

[406] FERC Stats. & Regs. at 31,729–30; *mimeo* at 277–78.

[407] *Mimeo* at 769.

[408] FERC Stats. & Regs. at 33,110 and 31,804–05; *mimeo* at 85 and 497–98.

determinations discussed in the Final Rule.[409]

(2) Clarification of Accounting Issues

In the Final Rule, the Commission offered clarifications on the Final Rule pro forma tariff requirements and certain other accounting issues related to the Final Rule.[410]

(a) Transmission Provider's Use of Its System (Charging Yourself)

In the Final Rule, the Commission stated that the purpose of functional unbundling is to separate the transmission component of all new transactions occurring under the Final Rule pro forma tariff, thereby assisting in the verification of a transmission provider's compliance with the comparability requirement. With respect to off-system sales, the Commission stated that the transmission provider would book to operating revenue accounts those revenues received from the customer to whom it made the off-system sale.[411] The Commission required that the transmission service component and energy component of those revenues be recorded in separate subaccounts of Account 447, Sales for Resale.

Rehearing Requests

APPA argues that the revenue from the transmission component of *all* off-system uses must be included in the credit if comparability is to be achieved.

APPA also argues that booking revenue credits to Account 447 for a test year reduction does not ensure timely receipt by customers. It asserts that a monthly pass-through to all firm transmission customers is needed.

APPA further argues that a properly functioning revenue credit does away with the perception of disparate treatment of network and point-to-point customers. Similarly, TDU Systems argues that comparability requires that revenues attributable to transmission owners' use of their transmission systems be flowed through to customers' benefit immediately so that transmission owners and customers receive comparable price signals with regard to their uses of the system.

Commission Conclusion

The precise methodology to be used to credit revenues from off-system sales for the benefit of the tariff customers should be addressed in the compliance filing proceedings and will depend on the particular rate design methodology that is ultimately employed. APPA's proposed monthly pass-through of revenue credits raises potential issues including: (1) use of estimates versus actuals; (2) the appropriate time period to be utilized; and (3) firm versus non-firm distinctions. Accordingly, the issue of determining appropriate revenue credits is properly left for case-by-case determinations. However, we agree with APPA that revenue from the transmission component of all off-system uses of the transmission system (whether by the transmission provider or a transmission customer) must be treated on a comparable basis, whether through rate design or through revenue credits.

(b) Facilities and System Impact Studies

In the Final Rule, the Commission explained that comparability mandates that to the extent a transmission provider charges transmission customers for the costs of performing specific facilities studies or system impact studies related to a service request, the transmission provider also must separately record the costs associated with specific studies undertaken on behalf of its own native load customers, or, for example, for making an off-system sale.[412]

Rehearing Requests

No requests for rehearing addressed this matter.

(c) Ancillary Services

In the Final Rule, the Commission indicated that, at this time, it was not convinced that the amounts involved or the difficulty associated with measuring the cost of ancillary services warrants a departure from our present accounting requirements.[413]

Rehearing Requests

No requests for rehearing addressed this matter.

(3) Miscellaneous Clarifications

(a) Electronic Format

In the Final Rule, the Commission required that public utilities, in addition to complying with the requirements of Part 35, submit a complete electronic version of all transmission tariffs and service agreements in a word processor format, with the diskette labeled as to the format (including version) used, initially and each time changes are filed.[414]

Rehearing Requests

No requests for rehearing addressed this matter.

(b) Administrative Changes

In the Final Rule, the Commission set forth a number of tariff modifications that it indicated needed no further explanation.[415]

8. Specific Tariff Provisions

The Commission attached a pro forma tariff to the Final Rule as Appendix D. A number of entities have sought rehearing of various sections of that pro forma tariff. Their arguments and the Commission's responses are set forth below.

Rehearing Requests

Oklahoma G&E asks that the Commission add a definition for ''Interconnection'' that would be an interface where one or more points of delivery or points of receipt are located.

Commission Conclusion

We disagree with Oklahoma G&E that there is a need to add a definition for ''Interconnection'' to the Final Rule pro forma tariff. Oklahoma G&E has not supported its need for the proposed change and has failed to identify any potential problems that may result if its definition is not included.

Sections 1.12, 15.4 and 32.4

Rehearing Requests

Cajun argues that the Commission should mandate joint planning in the development of Facilities Studies. It alleges that a transmission provider's independent long-range plans frequently include longer, higher voltage facilities than are needed for the transmission customers' requirements. It further alleges that absent mandatory joint transmission planning, the transmission customers will always be paying for the incremental capacity cost of transmission enhancements that only fit into the Transmission Provider's independent long-range plans.

Commission Conclusion

A joint planning mandate as recommended by Cajun, NRECA and others is beyond the scope of this proceeding. However, the Commission encourages 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. Moreover, on a regional basis, the Commission encourages the formation

[409] FERC Stats. & Regs. at 31,763; *mimeo* at 378.

[410] FERC Stats. & Regs. at 31,763–64; *mimeo* at 379–80.

[411] FERC Stats. & Regs. at 31,764; *mimeo* at 380–81.

[412] FERC Stats. & Regs. at 31,764; *mimeo* at 381–82.

[413] FERC Stats. & Regs. at 31,764–65; *mimeo* at 382–83.

[414] FERC Stats. & Regs. at 31,766; *mimeo* at 386.

[415] FERC Stats. & Regs. at 31,766–67; *mimeo* at 386–88.

of RTGs and ISOs to represent the needs of all participants in a region in the planning process.

Section 1.14

Rehearing Requests

CCEM asserts that the term Good Utility Practice is vague. It argues that the Commission should delete the reference to regional practices, but if it does not, the term should be clearly defined in each utility's tariff.

Commission Conclusion

The Commission recognizes that unique operating practices and conditions exist on a regional basis throughout the industry. Accordingly, the Commission permits certain deviations to the non-price terms and conditions of the tariff. In the Final Rule, we stated that any proposed modifications by the utility to the tariff to recognize regional operations and practices must be demonstrated to be reasonable, generally accepted in the region, and consistently adhered to by the transmission provider.[416]

Sections 1.22 and 1.25

Rehearing Requests

Blue Ridge requests clarification that a portion of a designated network resource need not consist of the entirety of a generating unit.

Commission Conclusion

Blue Ridge's request for clarification in the definition of ''Network Load'' in Tariff Section 1.22 and ''Network Resource'' in Tariff Section 1.25 is not necessary. Blue Ridge's concerns are based on the mistaken premise that a designated network resource must consist of the entirety of a generating unit. Tariff sections 1.25 and 30.1 explicitly specify that a network resource can be a *portion* of a generating resource or unit. Indeed, the Commission recently emphasized this point:

Ohio Cooperatives have disregarded the fact that a designated resource can be a part of a unit. In this example, Ohio Cooperatives would make two network designations for the 300 MW unit: a 100 MW designation for the 100 MW load on one system and a 200 MW designation for the 200 MW on the other system.[417]

Sections 1.25 and 30.1

Rehearing Requests

TDU Systems asserts that these sections should not be read to require assignment of specific Network Resources to specific control areas. They state that multiple control area network customers need to be able to dispatch their resources economically to serve their loads. They argue that the Commission would be in error to require that a transmission customer's resources be segmented if they are being dispatched to serve network load in one of several control areas and once so segmented, sales from such units be considered either third-party sales or become interruptible as to network load in a second control area and thus are not deemed Network Resources. They further argue that TDU systems with loads and resources in multiple control areas must be allowed to designate as Network Resources for each control area the totality of their resources which meet the owned or purchased requirements of section 1.25.

TDU Systems argues that these sections should be revised to include resources that are leased by a network customer on terms tantamount to ownership, or which, at a minimum, afford the network customer a first call right to that generating resource.

Commission Conclusion

TDU Systems' proposed revision to recognize leased resources appears reasonable and we revise these sections of the pro forma tariff, in relevant part, as follows (new text underlined, deleted text in brackets):

1.25 Network Resource: Any designated generating resource owned, [or] purchased *or leased* by a Network Customer under the Network Integration Transmission Service Tariff.

30.1 Designation of Network Resources: Network Resources shall include all generation owned, [or] purchased *or leased* by the Network Customer designated to serve Network Load under the Tariff.

Sections 1.33 and 1.34

Rehearing Requests

CCEM states that sections 1.33 and 1.34 should be changed to facilitate umbrella service agreements that include all points of receipt and delivery on a transmission provider's system.

Commission Conclusion

Consistent with our ruling in section IV.G.6 (Umbrella Service Agreement) regarding umbrella type service agreements for short-term firm point-to-point transmission service, we will modify sections 1.33 and 1.34 to require that Points of Receipt and Points of Delivery be specified in the service agreement for only Long-Term (more than one year) Firm Point-to-Point Transmission service.

Section 1.47

Rehearing Requests

Wisconsin Municipals asks the Commission to clarify that a utility is not prevented from including the load of interruptible customers in the denominator of the fraction used to perform the load ratio calculation. It claims that this is important in Wisconsin where the transmission system is planned without regard to the distinction between firm and interruptible power customers (interruptible customers are not subject to interruption for transmission reasons).

Commission Conclusion

The treatment of interruptible loads in the planning and operation of the Wisconsin transmission grid present a unique, case-specific situation that is best addressed on a case-by-case basis. As the Commission stated in the Final Rule:

all tariffs need not be ''cookie-cutter'' copies of the Final Rule tariff. Thus, under our new procedure, ultimately a tariff may go beyond the minimum elements in the Final Rule pro forma tariff or may account for regional, local, or system-specific factors. The tariffs that go into effect 60 days after publication of this Rule in the Federal Register will be identical to the Final Rule pro forma tariff; however, public utilities then will be free to file under section 205 to revise the tariffs, and customers will be free to pursue changes under section 206.[418]

Section 1.48

Rehearing Requests

Oklahoma G&E asks the Commission to clarify that the term ''Transmission Service'' as used in the pro forma tariff includes service provided on a network basis as well as on a point-to-point basis.

Commission Conclusion

The Commission used the term ''Transmission Service'' throughout the pro forma tariff to refer only to point-to-point service and not network service. We also note that the term ''transmission service'' (in lower case), which is also used throughout the pro

[416] FERC Stats. & Regs. at 31,770; *mimeo* at 397–98. The Commission has applied its approach to regional practices in filings made in compliance with Order No. 888. *See, e.g.,* American Electric Power Service Corporation, *et al.,* 78 FERC ¶ 61,070 (1997); Allegheny Power System, Inc., *et al.,* 77 FERC ¶ 61,266 (1996); Atlantic City Electric Company, *et al.,* 77 FERC ¶ 61,144 (1996).

[417] Order On Non-Rate Terms and Conditions, 77 FERC ¶ 61,144 (*mimeo* at 15–16) (1996).

[418] FERC Stats. & Regs. at 31,770 n. 514; *mimeo* at 399 n. 514.

forma tariff, was used to refer to both point-to-point and network service. Oklahoma G&E has not identified any problems associated with our use of these terms and therefore has not supported its proposed modification.

Section 1.49

Rehearing Requests

Santa Clara and Redding state that the transmission system is defined as facilities owned, controlled or operated and that this could result in the same transmission facilities being the part of the transmission system of two entities (*e.g.*, COTP, which is owned by TANC, but operated by Western Area Power Administration (WAPA)). They ask the Commission to clarify that only one such entity should have the obligation to provide transmission service.

Commission Conclusion

This presents a fact-specific situation that is best addressed on a case-by-case basis. This situation would appear to arise for WAPA and TANC only if either utility receives a request for reciprocal transmission service or if either utility files a voluntary tariff. The appropriate entity to include the COTP facility in its transmission system for purposes of a transmission tariff may depend upon the circumstances of the transmission request. Therefore, a resolution of this question is appropriately deferred until such time as reciprocal service using the COTP facility is requested.

Section 3

Rehearing Requests

CCEM asks the Commission to clarify that a transmission customer may switch its supplier of ancillary services.

Commission Conclusion

The Final Rule requires that transmission customers obtain all necessary ancillary services for their transactions. They must purchase certain of these services from the transmission provider, but can self supply or obtain certain services from a third party. Consistent with these requirements, a transmission customer may switch suppliers of ancillary services not required to be provided by the transmission provider if it continues to demonstrate that it satisfies its ancillary service obligations.

Section 5.1

Rehearing Requests

ConEd points out that this section applies to Transmission Service, which the tariff defines to mean point-to-point service only. It requests that this section be clarified to include network service.

Commission Conclusion

The use of the term ''Transmission Service'' in section 5.1 of the pro forma tariff was an inadvertent error. We will change the term ''Transmission Service'' used in section 5.1 to ''transmission service'' so as to include both point-to-point and network transmission service.

Section 6

Rehearing Requests

CCEM asks the Commission to require that the text of the required sworn statement by non-transmission owning entities that they are not assisting an Eligible Customer be included in the tariff.

Commission Conclusion

We will deny CCEM's request as unnecessary. The Commission does not believe that it must mandate the precise text of the required sworn statement. Rather, the entity requesting transmission service properly has the burden of explaining in a sworn statement the circumstances of its service request, including on whose behalf it may be requesting service (for itself or for another party).

Section 8

Rehearing Requests

CCEM argues that, consistent with Commission policy for natural gas pipelines, transmission providers should be required to refund all ''penalties'' that are in excess of the costs incurred to balance transmitting system operations (citing Transco, 55 FERC ¶ 61,446 at 62,372 (1991) and TETCO, 62 FERC ¶ 61,015 at 61,117 (1993)).

Commission Conclusion

CCEM's argument is premature. Order No. 888 did not establish a rate or a penalty for Energy Imbalance Service. CCEM is free to raise this concern at such time as utilities file their proposed rates for Energy Imbalance Service.

Section 11

Rehearing Requests

CCEM contends that an unconditional and irrevocable letter of credit is extremely costly to obtain and could be used as subterfuge for discriminatorily denying service. CCEM argues that if an irrevocable letter of credit is used, a transmission provider should not be able to draw on it until it tenders a bill that has been improperly refused. (CCEM attached a proposed conditional letter of credit to its rehearing request). Several entities argue that a letter of credit should not be required for existing customers with a satisfactory credit history and should only apply to new customers or those with a history of payment delinquency.[419]

Commission Conclusion

While a transmission provider may require an unconditional and irrevocable letter of credit, if a customer believes that the transmission provider unreasonably rejected an alternative security proposal, it may seek relief through the dispute resolution procedures established in Tariff Section 12. Moreover, if a customer believes a transmission provider is attempting to use the unconditional and irrevocable letter of credit in an unduly discriminatory manner, it may file a complaint raising such concern in a section 206 filing.

Section 12

Rehearing Requests

According to Public Service Co of CO, the dispute resolution procedures: (1) Should allow a party to appeal an arbitration award on the basis that arbitrators have misinterpreted the requirements of the pro forma tariff and (2) where a utility is a member of an RTG, should allow the RTG dispute resolution procedures to be exclusive. Otherwise, Public Service Co of CO argues, entities may perceive that the Commission's procedures are more favorable than the RTG's and decide not to join. Moreover, it asserts that when a utility that is a member of an RTG has a dispute with a customer that is a non-member, the customer's forum should be the Commission, or the RTG's procedures if those procedures apply to non-members.

Dispute Resolution Associates asks the Commission to require that prior to submission of disputes for arbitration or Commission disposition, disputants should be required to pursue a mediated resolution with a qualified individual. If unsuccessful, it states that parties can elect arbitration or Commission disposition. If successful, it states that parties will have avoided litigation related costs and will not have jeopardized their ongoing business relationship. Dispute Resolution Associates also argues that representatives at all negotiating sessions should be authorized to enter into an agreement and asks that the Commission clarify that dispute resolution is one of the minimum requirements of the Final Rule. It also asks that the Commission require that any filed separate retail transmission

[419] *E.g.*, Santa Clara, Redding, TANC.

tariffs must include section 12 type dispute resolution procedures.

Commission Conclusion

Concerning the first issue raised by Public Service Co of CO, even if the arbitrator misinterprets the requirements of the pro forma tariff, the dispute resolution procedures require such decision (as it affects terms and conditions of service) to be filed with the Commission. Section 12.2 provides:

> 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.

As to Public Service Co of CO's second concern, a utility's membership in an RTG with its own Dispute Resolution Procedures presents a fact specific situation to which a generic response is not appropriate. Whether both parties to a dispute are members of the RTG or only one of the parties is a member may have some bearing on which set of Dispute Resolution Procedures should apply.

Regarding Dispute Resolution Associates concerns, a utility is free to propose an initial process using ''mediated resolution with a qualified individual'' prior to using the Dispute Resolution Procedures. However, we see no need to modify the tariff to introduce such a proposed requirement as the Commission is not aware of other parties similarly claiming excessive costs or the threat of ''jeopardizing ongoing business relationship[s]'' due to the present Dispute Resolution Procedures. Finally, any attempts to delete the Dispute Resolution Procedures from any tariff on file with the Commission would require the transmission provider to demonstrate that its proposed modifications are consistent with or superior to the pro forma tariff terms and conditions.

Section 13.2

Rehearing Requests

CCEM asserts that the term ''reserved service'' should be changed to ''requested service.'' Utilities For Improved Transition and Florida Power Corp assert that the limitations on unconditional reservations are too stringent and that the Commission should modify the third sentence of section 13.2 to provide: ''If the Transmission System becomes oversubscribed, requests for longer-term service may preempt requests for shorter-term service up to a time period before the requested commencement of service that is equal to the requested term of service.''

Commission Conclusion

We will deny CCEM's request to replace the term ''reserved service'' in tariff section 13.2 with ''requested service.'' CCEM has not attempted to identify any uncertainties caused by the current wording of this section or explain any improvements that its proposed change would make.

Utilities For Improved Transition and Florida Power Corp's proposal to revise the deadline for when reservations for short-term firm transmission become unconditional is contrary to the Commission's intent in adopting the conditional reservation approach for short-term firm transmission and is rejected. Specifically, for service requests greater than a single day, week or month, Utilities For Improved Transition and Florida Power Corp's proposal decreases the period of time that such request is conditional; in other words, such request increases the unconditional reservation period, thus reducing the amount of longer-term transactions that the transmission provider can accommodate.

Sections 13.2 and 14.2

Rehearing Requests

CCEM notes that short-term firm point-to-point transmission service customers that have already reserved service have a right to match any longer-term requests for service before being preempted pursuant to section 13.2. However, CCEM states that these tariff sections do not establish a deadline for when such right must be exercised. Because the tariff established a conditional reservation period for short-term firm transmission service (during which time longer-term firm transmission requests can preempt shorter-term conditional reservations) CCEM suggests that a shorter-term firm transmission customer should be allowed to exercise its right to match longer-term service requests up until the end of the conditional reservation period. CCEM requests a similar clarification for non-firm transmission service but does not propose specific modification.

Commission Conclusion

While we agree with CCEM regarding the need to establish a deadline for exercising the right to match longer-term service requests for both short-term firm and non-firm transmission services, we will reject CCEM's proposed deadline for short-term firm transmission service. CCEM's proposed deadline would create market inefficiency by allowing the holder of the shorter-term firm transmission service an excessive amount of time to exercise its right to match the longer-term service. We feel that such a proposal could constitute a form of hoarding that would stifle the consummation of potential transactions and should not be allowed. CCEM's proposal would work to the detriment of any and all potential customer(s) requesting longer short-term firm transmission service. By allowing the original transmission customer to delay its response, the subsequent potential customer will be disadvantaged and may be required to make last minute alternative arrangements.

We believe that an especially quick response time is necessary for hourly non-firm transmission service customers to match longer-term service requests. Hourly non-firm transmission customers must exercise their right to match longer-term service requests immediately upon notification by the transmission provider of a longer-term competing request for non-firm transmission service. For non-firm transmission service other than hourly transactions and short-term firm transmission service, we believe a customer should exercise its right to match longer-term service requests as soon as practicable. The prompt exercising of such right is particularly critical where scheduling deadlines for such transactions are imminent. However, even for transactions with longer lead-times before service is to commence, we believe a response deadline of no more than 24 hours from being informed by the transmission provider of a longer-term competing request for transmission service is appropriate. Accordingly, the customer will be required to respond to the transmission provider as soon as practicable after notification of a longer-term request for service, but no longer than 24 hours from being notified or earlier if required to comply with the scheduling requirements for such services in tariff section 13.8 and 14.6. Tariff sections 13.2 and 14.2 will be modified accordingly.

Section 13.5

Rehearing Requests

Several utilities argue that section 13.5 is too broad because it also applies to costs that are included in rates on an embedded cost basis (which they claim can be evaluated when the transmission provider makes a rate filing).[420] They recommend that the Commission

[420] *E.g.*, Florida Power Corp, Utilities For Improved Transition, VEPCO.

modify the last sentence of the section as follows:

If redispatch costs or Network Upgrade costs are to be charged to the Transmission Customer on an incremental basis or costs relating to Direct Assignment Facilities that are to be charged to the Transmission Customer, the obligation of the customer to pay such costs shall be specified in the Service Agreement prior to the initiation of service.'' (Utilities For Improved Transition at 74–75).

Commission Conclusion

The Commission's intent in tariff section 13.5 was to require that any proposal to assess incremental charges to a customer must be specified in that customer's service agreement. Florida Power Corp and VEPCO correctly note that tariff section 13.5 inadvertently requires that *any* redispatch, network upgrade or direct assignment facilities, whether assessed on an incremental basis or included in embedded cost rates, must be specified in a customer's service agreement. To eliminate this unintended result, tariff section 13.5 is revised in relevant part as follows (new text underlined):

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.

Section 13.6

Rehearing Requests

CCEM asserts that the term ''Good Utility Practice'' should be deleted. CCEM claims that the inclusion of regional practices in Good Utility Practice makes the phrase vague and unpredictable. CCEM proposes that the Commission replace this phrase with a qualifier that pertains only to reliability and safety. According to PA Coops, equal priority places inordinate and unwarranted pressure on state siting and regulatory authorities to approve transmission projects required to provide service that may primarily benefit out of state parties. NYSEG argues that the Commission is not authorized to require curtailment of bundled retail service because it does not have jurisdiction over the rates, terms, and conditions of such service. It asserts that transactions subject to proportional curtailment should not include a transmitting utility's own use of its system to transmit its owned and purchased generation to native load customers as part of bundled retail service or services under rate schedules that are grandfathered. For transactions subject to proportional curtailment, NYSEG argues that allocation of curtailments will be comparable only if those multiple transactions being curtailed are of the same type of service and if each of the multiple transactions is for the same duration—these curtailments should be made on the same basis as required for non-firm PTP service. It asks the Commission to clarify that the curtailment requirements are not applicable to existing transmission contracts.

Commission Conclusion

CCEM's concerns center on the inclusion of the phrase regional practices in the definition of Good Utility Practice in section 1.14 of the pro forma tariff. These concerns are answered in section 1.14 above.

PA Coops' argument that long-term firm point-to-point transmission customers should be curtailed before network service customers and native load ignores the fact that the transmission provider has an obligation under the pro forma tariff to expand or upgrade its transmission system in response to requests for such long-term point-to-point transmission requests. In turn, such long-term firm point-to-point transmission customers undertake an obligation to pay for any transmission facility additions necessary for the provision of service pursuant to the tariff. Comparability requires that all long-term firm transmission customer be treated on a not unduly discriminatory basis in terms of curtailment priority.

Regarding NYSEG's arguments, the purpose of the curtailment provisions of the pro forma tariff is not to ''requir[e] curtailment of bundled retail service'' as NYSEG claims. Rather, the provision simply requires the transmission provider to curtail network and point-to-point transmission services on a basis comparable to the curtailment of the transmission provider's service to its native load. Indeed, we have repeatedly indicated that we do not have jurisdiction over bundled retail sales.

NYSEG's concerns regarding curtailment provisions in existing contracts are addressed above in Section IV.G.3.a. (Pro-rata Curtailment Provisions).

Section 13.7

Rehearing Requests

Utilities For Improved Transition and Florida Power Corp state that section 13.7 of the pro forma tariff makes it uneconomic to engage in system sales transactions on a firm basis because it requires the transmission provider to impose a separate charge for transmission from each generating station. They ask that the Commission clarify that if there is a sale from multiple generators, a reservation of transmission from each point of receipt will be required only in the amount of the expected relative contribution of each generating station to the energy that is sold. If it is not so clarified, they argue that the Commission should make one of the following modifications: (1) permit the customer to designate more than one generating station as a single point of receipt if it provides likely loadings of the units to the transmission provider; (2) provide that where the customer takes service from a group of generating stations on an economic dispatch basis, the reserved capacity is the sum of the reservations at the points of delivery (must also provide likely loadings); or (3) add a new subsection to Article 31 that provides that a network integration transmission customer may also reserve service on a contract demand basis for periods as short as one day (but do not reduce the one-year minimum term for load-based network service).

CSW Operating Companies asserts that the Commission should permit sales of power from multiple points of receipt, but such multiple generating units should be considered a single point of receipt. According to CSW Operating Companies, this provides maximum flexibility, lessens the need to establish secondary points of receipt, and is consistent with *FMPA* v. *FPL,* 74 FERC ¶ 61,006 at 61,014 (1996). They ask that the Commission revise section 13.7(b) to provide: ''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. Such multiple generating units shall be considered a single Point of Receipt when the underlying sale is to be made on a system basis and not from specific generating units.'' (CSW Operating Companies at 10–11). TAPS requests that the Commission clarify that a network customer may make system sales to third parties using the point-to-point provisions without designating each generating resource as a point of receipt. Moreover, it asks that if the Commission intends to depart from *FMPA* v. *FPL,* that transmission providers be held to the same burden.

Commission Conclusion

Several utilities request rehearing on the tariff's requirement that sales of capacity and energy from multiple generating units must be designated as multiple points of receipt under point-to-point transmission service. These parties generally claim that this tariff requirement makes system sales transactions uneconomical and is contrary to the Commission's determination in *FMPA* v. *FPL*, 74 FERC ¶ 61,006 at 61,014 (1996).

As the Commission stated in the Final Rule:

all tariffs need not be ''cookie-cutter'' copies of the Final Rule tariff. Thus, under our new procedure, ultimately a tariff may go beyond the minimum elements in the Final Rule pro forma tariff or may account for regional, local, or system-specific factors. The tariffs that go into effect 60 days after publication of this Rule in the Federal Register will be identical to the Final Rule pro forma tariff; however, public utilities then will be free to file under section 205 to revise the tariffs, and customers will be free to pursue changes under section 206.[421]

Utilities that advocate modifying the pro forma tariff to accommodate system sales are free to file their specific proposals with the Commission in a section 205 filing.[422] Such proposals are best reviewed on a case-specific basis where the type of system sales engaged in by the transmission provider or transmission customer can be identified and described in detail. In order to ensure comparability, any proposed tariff modifications submitted in order to facilitate system sales of the transmission provider must also apply for sales by transmission customers as well.

Section 13.7(b)

Rehearing Requests

Blue Ridge argues that because units at the same geographic location can be connected to the system at different electrical locations, such as connections at different voltage levels (e.g., one unit connected at 500 kV and another unit connected at 230 kV), the Commission should replace the phrase ''at the same generating plant'' with ''at the same electrical location.'' (Blue Ridge at 23–24).

Commission Conclusion

Blue Ridge's proposed change is unsupported. The rationale supporting the need for such change and its intended result is unclear and unexplained and appears to be unnecessary and overly restrictive. Many generating units at a single plant are connected to the transmission grid at multiple voltages. Therefore, taking Blue Ridge's proposal to its logical end, a customer could face an additional charge at a single unit for every voltage level connection. In contrast, the intent of section 13.7(b) of the pro forma tariff is to treat multiple units at a single plant as a single point of receipt to avoid charging a customer an unnecessary additional charge.

Section 13.8

Rehearing Requests

CCEM asks the Commission to clarify that permissible scheduling changes extend to changes in the amount of power scheduled, the generation source, and delivery and receipt points. AMP-Ohio asserts that if the transmission provider can accommodate a change, the customer should be able to change its schedule less than 20 minutes before the hour or during the hour, and during an emergency or when the customer is attempting to remain within the 1.5% deviation band. It also asks the Commission to clarify that customers should be allowed to aggregate multiple points of delivery of less than a whole megawatt to be stated in whole megawatts (as is allowed for points of receipt). Otherwise, AMP-Ohio asserts, this would preclude small utilities from receiving service under a transmission provider's open access tariff.

Commission Conclusion

We agree with CCEM that permissible scheduling changes include the amount of power scheduled (up to the amount of capacity reservation stated in the customer's service agreement). However, a proposed modification to the generation source or to receipt and delivery points on a firm basis under the pro forma tariff is not simply a scheduling change, as maintained by CCEM, but is a new request for service, as set forth in pro forma tariff section 22.2.

AMP-Ohio's request regarding scheduling changes ignores the optional language in section 13.8 of the pro forma tariff, which permits a reasonable time limitation (other than the stated twenty minute deadline) that is ''generally accepted in the region and is consistently adhered to by the transmission provider.'' Accordingly, the pro forma tariff may be amended by the transmission provider to reflect the prevailing practice in the region.

AMP-Ohio's request regarding scheduling changes to allow the customer to stay within the deviation band of 1.5 percent may not be feasible depending upon the ramping rates of the particular generating units and may allow erratic scheduling by customers that could interfere with the transmission provider's ability to provide load following service.

AMP-Ohio's request for clarification that customers should be allowed to aggregate multiple points of delivery of less than a whole megawatt is unnecessary. Tariff section 17.2(viii) specifically allows customers to combine their requests for service for either points of receipt or points of delivery in order to satisfy the minimum transmission capacity requirement.

Section 14.2

Rehearing Requests

Tallahassee asks the Commission to clarify that a non-firm customer facing possible interruption for economic reasons will be allowed to match the duration and price of the surviving transaction and that once a non-firm transaction begins, it will not be preempted without whatever notice is sufficient and appropriate in the region, but the time period should be no shorter than 1–2 hours.

Commission Conclusion

The pro forma tariff does allow a customer to match a longer term reservation before being preempted. Moreover, non-firm transmission transactions, by definition, are interruptible for economic reasons (on a non-discriminatory basis) at any time. To the extent a prevailing regional practice exists regarding advance notice of interruption, the transmission provider may incorporate such a provision in its tariff.

Section 14.4

Rehearing Requests

CCEM asks the Commission to clarify that a non-firm point-to-point service agreement is an Umbrella Agreement and a non-firm point-to-point customer should be able to schedule a transaction at different primary and secondary receipt points and schedule changes in primary points with no filing requirement.

Commission Conclusion

The form of service agreement for non-firm transmission service is a non-transaction specific umbrella service agreement (*See* Attachment B to the pro forma tariff). Therefore, the service agreement does not require a specification of receipt and delivery points for non-firm point-to-point transmission service. However, we note that changes to the receipt or delivery points for non-firm transmission service other than those points reserved by the transmission customer in its service request are not ''schedule'' changes as claimed by CCEM, but will require the

[421] FERC Stats. & Regs. at 31,770 n. 514; *mimeo* at 399 n. 514.

[422] See Commonwealth Edison Company and Commonwealth Edison Company of Indiana, Inc., 78 FERC ¶ 61,090 (January 31, 1997).

submission of a new application for service pursuant to Tariff Section 18.

Section 14.6

Rehearing Requests

CCEM asks the Commission to clarify that ''scheduling changes'' for non-firm transmission include changes in the amounts scheduled, changes in receipt and delivery points, or changes in primary points.

Commission Conclusion

This issue is addressed in Section 13.8 above.

Sections 17, 18 and 29.2

Rehearing Requests

The EPRI/NERC Working Group (formerly the ''What and How Industry Working Group'') identifies certain areas in the pro forma tariff ''where the perceived scope of OASIS has grown beyond that which is feasible in Phase 1'' of OASIS. (EPRI/NERC Working Group at 2). EPRI/NERC Working Group references various information required in the application process under the pro forma tariff that is required to be submitted via OASIS to the transmission provider. EPRI/NERC Working Group explains that a substantial amount of information required under the pro forma tariff ''cannot be provided via the OASIS in Phase 1'' (*e.g.,* service agreements, requests for (A) non-firm point-to-point transmission service in the next hour, (B) multiple receipt and delivery points, (C) addition of new network loads or resources, loadflow and stability data).

The EPRI/NERC Working Group also claims that tariff section 17.1 creates confusion as it first requires that ''[a] request for Firm Point-To-Point Transmission Service * * * *must contain a written Application* * * *'' to the transmission provider, but then requires ''[a]ll Firm Point-To-Point Transmission Service requests should be *submitted by entering the information listed below on the Transmission Provider's OASIS.*'' (Emphasis added). The EPRI/NERC Working Group asserts that the above language confuses the process of an ''application for service agreement'' versus the process of ''a request for transmission service'' by a customer who already has a service agreement.

Commission Conclusion

The Commission recognizes that implementation of the OASIS is being accomplished in phases. In recognition of this fact, section 17.1 of the pro forma tariff provides:

> 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.

Moreover, we clarify that if Phase 1 of OASIS implementation does not support the submission of certain information over the OASIS, such information may be submitted by telephone or telefax (facsimile), as provided in the pro forma tariff, and promptly (within one hour) posted on OASIS by the Transmission Provider.[423]

Concerning the EPRI/NERC Working Group's apparent confusion regarding service application processes, we previously explained in Section IV.G.6 that the Commission is modifying the application process for firm point-to-point transmission transaction of less than one year (short-term firm transactions). The Commission will permit an ''umbrella service agreement'' approach where all of a customer's short-term firm transactions can be arranged under a single non-transaction specific umbrella service agreement rather than requiring a new service agreement for each short-term firm transaction. In contrast, service agreements for firm point-to-point transmission transactions of one year or more (long-term firm transactions) are transaction specific and require a separate service agreement for each transaction.

Section 17.1

Rehearing Requests

CCEM states that the 60 days in advance to request service should be shortened to 6 days. For service shorter than one year, it argues that the procedures should not be left to negotiation with a monopolist. For service greater than one month but less than one year, it asserts that a request should be submitted 3 days in advance; for weekly service, schedules should be submitted by some specific hour the day before service is to commence; and for hourly or daily service, schedules should be submitted no later than 20 minutes in advance.

Commission Conclusion

CCEM has provided no support for its proposal to shorten the lead time for requests for firm service from sixty days to six days. Sixty days in advance of the commencement of long-term (greater than one year) firm service is not an unreasonable time period. It provides transmission providers time to conduct security analyses, as well as perform system impact studies and facility studies that may be necessary. Accordingly, CCEM's request is denied.

Section 17.2

Rehearing Requests

CCEM argues that information concerning the location of the generating facility and the load ultimately served is not required in connection with a good faith request under the Policy Statement Regarding Good Faith Request for Transmission Services and should not be required in a Completed Application. However, if it is required, CCEM argues that it should remain confidential and not be disclosed. It further asks the Commission to clarify that a point-to-point customer can designate all receipt and delivery points in order to obtain umbrella-type service and can schedule receipt and delivery points as primary or secondary and can change primary points by filing another schedule.

Commission Conclusion

We will deny CCEM's proposed changes in part as unnecessary. The locations of generating facilities and loads are needed by the transmission provider to allow it to analyze whether the requested transmission service can be accommodated over the existing transmission system, as well as to plan upgrades and transmission facility additions.[424]

Tariff section 17.2 already requires that ''the transmission provider shall treat this [confidential] information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.''

With respect to CCEM's request to permit umbrella-type service, we note that we have adopted an umbrella-type service agreement approach for short-term firm transmission service, as

[423] On December 27, 1996, the Commission issued an order that found that

> During Phase 1, a request for transmission service made after 2:00 p.m. of the day preceding the commencement of such service, will be ''made on the OASIS'' if it is made directly on the OASIS, or, if it is made by facsimile or telephone *and* promptly (within one hour) posted on the OASIS by the Transmission Provider.

77 FERC ¶ 61,335 (1996).

[424] We further note that CCEM's reference to the Commission's Policy Statement Regarding Good Faith Request for Transmission Services does not support its position. As we there stated,

> [a] good faith request for transmission service should also contain a specific, technical description of the requested services in sufficient detail to permit the transmitting utility to model the additional services or its transmission system.

FERC Stats. & Regs. ¶ 30,975 at 30,863.

discussed in Section IV.G.6 (Umbrella Service Agreements).

Section 17.3

Rehearing Requests

CCEM asserts that a customer determined to be creditworthy should not have to submit a deposit for firm point-to-point transmission service. CCEM would limit this section to those customers found not to be creditworthy and asks the Commission to clarify that only the costs of system impact studies or facilities studies can be deducted from the deposit.

Commission Conclusion

Section 17.3 reflects a standard requirement in many existing tariffs and other agreements on file with this Commission. CCEM provides no compelling reason to revise this tariff provision.

We also deny CCEM's request regarding deductions from the deposit. We will not preclude a utility from demonstrating that it incurs costs other than system impact studies or facilities studies in processing a service application and arguing that these costs should be deducted from a deposit.

Section 17.4

Rehearing Requests

CCEM argues that a deficiency determination should be made in, at most, one day.

Commission Conclusion

CCEM provides no compelling reason to revise this tariff provision. CCEM's argument also ignores the fact that certain applications involve more complex unique transactions and associated arrangements which may require more time to review than other more standard applications. CCEM's apparent concern regarding deficient applications should be mitigated by the pro forma tariff requirement that the transmission provider must attempt to remedy minor deficiencies in the application informally with the transmission customer.

Section 17.5

Rehearing Requests

CCEM asserts that a transmission provider should respond to a completed application for firm transmission service within 10 minutes for hourly service, 10 minutes for daily service, 4 hours for weekly service, 1 day for monthly service, 2 days for service longer than one month but less than one year, and 5 days for service one year or longer.

Commission Conclusion

Section 17.5 requires the transmission provider to notify the eligible customer *as soon as practicable,* but no later than 30 days after receipt of a completed application if it can provide the service or if a system impact study will be required. We do not believe that further specificity in establishing deadlines for each type of service and duration of service is necessary. However, we are clarifying section 17.5 to require that all responses be made on a non-discriminatory basis. If CCEM believes the transmission provider is engaging in discriminatory behavior by delaying responses to service requests (or by responding to service requests by its wholesale merchant function more quickly than it responds to service requests by unaffiliated customers), it can file a section 206 complaint with the Commission.

Section 17.7

Rehearing Requests

Several utilities ask the Commission to clarify that, if transmission facilities have been constructed to accommodate a request for transmission service, delays by the customer in commencing service should be prohibited or the customer should pay the full carrying charges on the facilities during the period of delay (less any revenues received).[425] Similarly, EEI and Southern argue that if new facilities are constructed, but the customer postpones service by paying a reservation fee, fairness requires that the customer bear its cost responsibility for the new construction at the time the facilities are ready to be used.

Commission Conclusion

Because different factual circumstances could exist that may lead to alternative solutions to the problem, we will not adopt a generic resolution. Rather, the Commission believes it appropriate to allow each utility to propose solutions in subsequent section 205 filings with the Commission.

Section 19

Rehearing Requests

VA Com asks the Commission to clarify that determining the necessity of a transmission facility upgrade or addition remains a state prerogative. It asserts that native load customers may face reduced reliability, or may incur costs associated with premature additions, if calculations of ATC are incorrect. In addition, it asserts that generating facilities can also be used to relieve regional capacity constraints—''For example, a current proposal by Virginia Electric and Power Company (''Virginia Power'') seeks the Virginia Commission's approval of a major new transmission line. Virginia Power alleges that the line is needed since it would increase the availability of emergency off-system supplies and allow it to lower its capacity reserve requirements. If the Virginia Commission were to approve the line, it is conceivable that FERC could direct Virginia Power to use this additional interchange capability to facilitate wholesale wheeling transactions. In such an event, native load customers may be adversely affected since the utility would be forced to suffer diminished reliability or build additional generation or transmission facilities.'' (VA Com at 10–12). CCEM asks the Commission to require studies for short-term firm point-to-point service or requests for capacity that are posted on the OASIS.

Commission Conclusion

In the Final Rule, the Commission explicitly stated that

> public utilities may reserve existing transmission capacity needed for native load growth and network transmission customer load growth reasonably forecasted within the utility's current planning horizon. However, any capacity that a public utility reserves for future growth, but is not currently needed, must be posted on the OASIS and made available to others through the capacity reassignment requirements, until such time as it is actually needed and used.[426]

This ability to reserve capacity to meet the reliability needs of native load would apply equally to transmission built in the future.

VA Com requested clarification of the intended treatment by the Commission in the ATC calculation of a transmission line built in lieu of generation for purposes of lowering reserve requirements for native load. If it seeks to withhold capacity in response to a request for service by an eligible customer, the transmission provider will have the burden of proof to demonstrate that any reserved capacity is needed for meeting native load and network customers' load growth or for purposes of meeting a reserve requirement level that is reasonable.

CCEM's request is unnecessary because system impact studies and facilities studies are required pursuant to tariff section 19 for both long-term and short-term firm point-to-point transmission service.

[425] *E.g.,* Utilities for Improved Transition, Florida Power Corp, VEPCO.

[426] FERC Stats. & Regs. at 31,694; *mimeo* at 172.

Sections 19.2 and 32.2

Rehearing Requests

Utilities For Improved Transition and VEPCO ask the Commission to modify these sections to require that a system impact study agreement specify the estimated charge instead of the maximum charge so that the transmission provider may collect all prudently incurred study costs.

Commission Conclusion

Utilities For Improved Transition and VEPCO correctly note that the use of the phrase ''maximum'' in the language of tariff sections 19.2 and 32.2 may prevent a utility from collecting the full costs of conducting a system impact study despite acting in a prudent manner. Accordingly, the relevant portion of these sections are modified as shown below to eliminate this potential inequity (deleted text in brackets):

(i) The System Impact Study Agreement will clearly specify [the maximum charge, based on] 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.

Sections 19.3 and 19.4

Rehearing Requests

TAPS asserts that the 15-day periods for customers to execute a service agreement after completion of a system impact study are too short and should be lengthened to 30 days or the transmission provider should be allowed to provide an extension for cause (with public notice) while the customer is pursuing an agreement in good faith.

Commission Conclusion

TAPS' proposed changes are not necessary because the eligible customer is provided a sufficient response time considering the situation to which the eligible customer is responding. Specifically, the 15-day period in section 19.3 refers to the situation where the transmission provider has conducted a system impact study and concluded that the requested service can be provided without the need to modify its transmission system. TAPS provides no reason why the eligible customer requesting the service should not be prepared to immediately accept the offer to provide service at the transmission provider's standard rate (without the need for upgrades, the eligible customer would not be assessed incremental transmission charges).

Similarly, the 15-day period in section 19.4 refers to the time in which the eligible customer has to execute a facilities study agreement in which it agrees to pay the transmission provider for the costs of conducting a facilities study. In contrast, when the facilities study is completed and the eligible customer is provided with a good faith estimate of any direct assignment facilities and/or share of any network upgrades, section 19.4 provides the eligible customer with 30 days to respond.

Section 22.1(d)

Rehearing Requests

Utilities For Improved Transition and Florida Power Corp ask the Commission to modify this section to require that a request for modification of service on a non-firm basis be made by submitting a modification to the original application with an OASIS posting. Otherwise, they assert, this section implies that such modifications would occur without using the transmission provider's OASIS.

Commission Conclusion

Utilities For Improved Transition and Florida Power Corp misinterpret this section of the tariff. The Commission's intention is simply to clarify that the customer's request to modify its firm transmission service to receive service over secondary receipt and delivery points on a non-firm basis would not require a separate application for *non-firm transmission service.* The concerns expressed with respect to posting on the OASIS are addressed in Order No. 889–A.

Section 23.1

Rehearing Requests

CCEM asserts that the Commission sHhould specify the filings necessary for assignment of service referenced in this section or delete the clause. In addition, CCEM asks the Commission to clarify that the identical services will be provided at no additional cost to the assignee or the reseller.

Commission Conclusion

The pro forma tariff is a tariff of general applicability. For administrative reasons, the listing of every conceivable situation in which an assignment or transfer of service from one entity to another may require a separate filing is not feasible. For example, if the Commission lists only a single situation that requires a separate filing and subsequently determines another situation would also require a filing, all of the pro forma tariffs on file with the Commission would need to be revised to reflect the change.

CCEM's request that the Commission clarify that reassigned services will be provided at no extra cost is also denied. CCEM ignores the fact that nothing in the pro forma tariff prevents the transmission provider from seeking a change in rates pursuant to a section 205 filing whether such filing relates to a general increase in rates to all transmission customers or to additional costs the transmission provider asserts it incurs due to providing service to an assignee. As always, the transmission provider bears the burden of proof of demonstrating that its proposal is just and reasonable.

Section 23.2

Rehearing Requests

CCEM asks the Commission whether an assignee can change primary points if there is only a partial assignment.

Commission Conclusion

Whether the assignment is full or partial is immaterial. If an assignee wishes to change its receipt or delivery points on a firm basis (full or partial), the request will be treated as a new request for service as required under tariff sections 22.1 and 23.1. However, if an assignee wishes to change receipt or delivery points on a non-firm (full or partial) basis, such change can be accomplished without the need for a new service agreement as provided in pro forma tariff section 22.1.

Sections 25 and 34

Rehearing Requests

VT DPS asks the Commission to revise these sections to state that ''all firm customers should share in non-firm revenues'' consistent with the language of the preamble.

Commission Conclusion

VT DPS' request is denied. The Commission did not intend to mandate the rate methodology used to reflect any cost reductions that may be associated with the provision of non-firm transmission service. While the Commission would generally expect all firm customers to share in non-firm revenues, the use of revenue credits is not the only acceptable method of reflecting non-firm system usage. The transmission provider's method of reflecting revenues from non-firm service should be addressed on a case-by-case basis.

Section 29.1

Rehearing Requests

TAPS contends that, to avoid improper use of operating agreements by transmission providers, the

Commission should either permit network operating agreements to be filed in unexecuted form or include a network operating agreement as part of the pro forma tariff.

Commission Conclusion

The network operating agreement is expected to be a highly detailed agreement between the transmission provider and network customer that establishes the integration of the network customer within the transmission provider's transmission system. Due to the unique characteristics of network customers' systems and the level of customer-specific information and arrangements required under a network operating agreement, it is likely that each network operating agreement will be different for each customer. Accordingly, the Commission does not believe it appropriate to mandate a particular form of network operating agreement for inclusion in the pro forma tariff. However, if a transmission provider wishes to include a generic form of network operating agreement in its pro forma tariff (to be modified as required and as mutually agreed to on a customer-specific basis), it may propose to do so in a section 205 filing or it may file an unexecuted network operating agreement in a section 205 filing.

To the extent a customer believes a transmission provider is engaging in unduly discriminatory practices via the network operating agreement, the customer may file a section 206 complaint with the Commission.

Section 29.4

Rehearing Requests

TDU Systems asserts that this section does not identify who should determine what facilities are ''necessary to reliably deliver capacity and energy. * * *'' It asks the Commission to clarify that this is solely the responsibility of the transmission customer.

Commission Conclusion

TDU Systems' argument ignores tariff section 35.1, which specifies:

> [t]he Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice *and in conformance with the Network Operating Agreement.* (emphasis added)

Accordingly, the determination of what network customer facilities are ''necessary to reliably deliver capacity and energy * * *'' is to be agreed upon by both the transmission provider and network customer and specified in the network operating agreement. To the extent the parties do not agree, the transmission provider will file an unexecuted network operating agreement with the Commission and we will resolve the dispute.

Section 30.1

Rehearing Requests

VT DPS argues that, consistent with section 30.7, section 30.1 should not require that a network resource be available on a strictly non-interruptible basis.

Commission Conclusion

VT DPS' request is denied. The Commission believes that a network customer should only be allowed to designate non-interruptible network resources. To allow otherwise would interfere with the planning process as well as the day-to-day operation of the transmission system to integrate resources with customer's loads (*e.g.*, the transmission provider will be unable to plan for what generation resource will be available to meet a customer's load in the event its designated resource is subject to interruption). Similarly, for operational purposes on a day-to-day basis, an interruption of a network customer's designated resource could cause a transmission constraint.[427] Because constraints affecting reliability may lead to curtailment or redispatch of all network resources, other network customers would be affected by such interruptions on a load-ratio basis. However, to the extent a network customer wishes to use an interruptible generation source, it can still use this generation source on an as-available basis to import energy to serve its load pursuant to pro forma tariff section 28.4.

Section 30.4

Rehearing Requests

PA Coops ask the Commission to modify this section ''to permit the Network Resources to be operated at outputs that exceed the Network Customer's designated Network Load plus losses when the Network Resource's output is being sold to a third party or the Network Resource is called upon to be operated by the Network Customer's power pool, ISO or control area operator.'' (PA Coops at 8–9). Similarly, Santa Clara and Redding ask the Commission to modify the last sentence to state: ''* * * exceeds its designated Network Load, plus non-firm sales delivered under Part II, plus losses'' so that network resources will not remain idle when they could otherwise generate non-firm power and energy for sale at competitive prices.

In addition, TDU Systems argues that the arbitrary limits on the ability of network customers to operate Network Resources prevents economic dispatch or the use of resources to meet load requirements and limits the ability to schedule the output of Network Resources between and among control areas, effectively preventing the network customer from operating an integrated system.[428] TDU Systems asserts that the Commission should not presume that a network customer's economic dispatch will burden a transmission provider, but should require a transmission provider to demonstrate that such a burden will occur. TAPS asks the Commission to clarify this section so as to bar not the operation of network resources in excess of network load, but rather the usage of network service in connection with operation of such resources in excess of network load. TAPS adds that section 30.4 is contrary to *FMPA* v. *FPL,* 74 FERC at 61,014–15. AEC & SMEPA argues that the Commission should provide the necessary latitude for such resources to be used across multiple control areas to service the total load of transmission users.

Commission Conclusion

Preliminarily, TDU Systems and others' argument that a designated network resource must consist of the entirety of a generating unit is mistaken, as we explained in sections 1.22 and 1.25 above. The Commission's intent in requiring that the output of network resources not exceed network load plus losses is to prevent designated network resources from being used to make firm sales to third parties. This is consistent with the pro forma tariff's requirement in sections 1.25 and 30.1 that:

> 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.

Absent a requirement that network resources always be available to meet a customer's network loads, reliability of service to the network customer as well as to native load and other network customers could be affected, as we describe in detail in section 30.1 above. If a network customer desires to enter into a firm sale from its designated network resources or use such network resources for meeting reserve requirements, it must eliminate the appropriate resources or portions thereof from its designated network

[427] While firm resources can also go off line, the probability of this happening is less than that for interruptible resources.

[428] *See also* NRECA.

resources pursuant to pro forma tariff section 30.

Santa Clara, Redding and others contend that this limitation improperly restricts the use of network resources for non-firm sales. It was not the Commission's intent to prohibit the network customer from engaging in non-firm sales from idle designated network resources. We find that the non-firm operation of network resources will not affect the availability of such resources on a firm basis because such non-firm uses are subject to interruption. Accordingly, the Commission's concerns regarding the reliable provision of network service are satisfied.

Furthermore, as noted by Pennsylvania Coops, emergencies could arise in which the transmission provider may request that a network customer alter the operation of its network resources in response to a contingency, which action could result in a violation of the limitation in section 30.4. Therefore, the Commission believes an exception to the network resources output limitation is also appropriate for such emergency situations. Accordingly, tariff section 30.4 is revised, in relevant part, consistent with the above findings, as shown below (emphasis added):

> 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 its Transmission System.*

The remaining concerns expressed by TDU Systems with respect to the economical operation of a network customer's loads and resources located in multiple control areas are addressed above in Section IV.G.1.b. (Network and Point-to-Point Customers' Uses of the System (so-called ''Headroom'')).

Section 30.6

Rehearing Requests

CSW Operating Companies asks the Commission to clarify that a customer has the obligation to replace the loss of a resource that is not physically interconnected with the transmission provider's transmission system within the time that is customary in the region or be subject to curtailment and suggests language to be included as section 33.8. CSW Operating Companies indicates that it intends to include a provision addressing this issue in the form of a network operating agreement included in the individual companies' Final Rule compliance tariffs.

Commission Conclusion

The Commission agrees with CSW Operating Companies that the appropriate place to address detailed operational requirements such as this is the Network Operating Agreement. If disputes arise, they can be addressed on a case-by-case basis.

Section 30.7

Rehearing Requests

Wisconsin Municipals asks the Commission to clarify that, for purposes of comparability between network and point-to-point customers, a customer may not reserve capacity for firm point-to-point transmission service until the customer can show that it owns or has committed to purchase generation under an executed contract that it intends to use over the reserved transmission contract path. Wisconsin Municipals claims that without the requirement to demonstrate ownership or contractual rights to the output of a generation resource, the point-to-point customers will have the advantage over network customers of being able to reserve transmission service over facilities with limited available transmission capacity earlier than network customers. Wisconsin Municipals also argues, in essence, that a single or a few point-to-point customers would be able to engage in hoarding of transmission capacity by reserving all available transmission capacity over certain transmission facilities.

Commission Conclusion

The arguments presented by Wisconsin Municipals in support of its proposal are misplaced. Wisconsin Municipals' assertion that point-to-point customers would be able to reserve transmission service over facilities with limited available transmission capacity earlier than network customers overlooks the fact that the Final Rule allows transmission providers to reserve existing transmission capacity needed for native load growth and network transmission customer load growth reasonably forecasted within the transmission provider's current planning horizon.[429] Wisconsin Municipals' concerns regarding hoarding of transmission capacity are answered in Section IV.C.6. (Capacity Reassignment). Finally, Wisconsin Municipals' argument that comparability requires that both network and point-to-point customers be required to demonstrate ownership or contractual rights to the output of a generation resource is not persuasive. Network and firm point-to-point transmission service are different services. Firm point-to-point transmission service is available for periods as short as one day, whereas network service is designed to accommodate a longer term of service with a minimum term of service of one year. The requirement to demonstrate ownership or contractual rights to generation for network service is necessary because the transmission provider must be able to serve the network load from any of the designated resources. In contrast, point-to-point service is a capacity reservation service between specified points of receipt and points of delivery. Accordingly, this network requirement does not need to be extended to firm point-to-point service under the guise of comparability.

Section 31.2

Rehearing Requests

TDU Systems asks the Commission to clarify that an application for new network load for an existing network customer need only address the additional network service needed to serve the new Network Load and does not in any way implicate the existing network service for which the network customer has already contracted.

Commission Conclusion

No clarification is necessary. Tariff section 31.2 explicitly states in relevant part:

> A designation of new Network Load must be made through a *modification of service* pursuant to a new Application. (Emphasis added)

Section 32.3

Rehearing Requests

TDU Systems asserts that this section requires too short a time for customers to evaluate a system impact study. It argues that, at a minimum, customers should have 60 days to evaluate a study and, in the event of a dispute, the application should remain viable until the dispute is resolved (also argues that the time periods set forth in sections 19.1, 19.4, 32.1, 32.3 and 32.4 are too short).

Commission Conclusion

TDU Systems' proposed changes are not necessary as the pro forma tariff provides an eligible customer sufficient time to respond to a system impact

[429] FERC Stats. & Regs. at 31,694; *mimeo* at 172.

study. Specifically, the 15-day period in section 32.3 refers to a situation where the transmission provider has conducted a system impact study and concluded that the requested service can be provided *without* the need to modify its transmission system. TDU Systems provides no reason why the eligible customer should not be prepared to immediately accept the offer of providing service at the transmission provider's standard rate (without the need for upgrades, the eligible customer would not be assessed incremental transmission charges).

Similarly, the 15 day period in sections 19.1, 19.4, 32.1 and 32.4 refer to the time in which the eligible customer has to agree to execute an agreement to pay the transmission provider for costs of conducting studies (a system impact study in sections 19.1 and 32.1 and a facilities study in sections 19.4 and 32.4). TDU Systems provides no reason why it should not be prepared to accept or reject the relatively minor costs of further studies to determine whether its requested transmission service can be accommodated by the transmission provider.

In contrast, when the facilities study is completed and the eligible customer is provided with a good faith estimate of any direct assignment facilities and/or share of any network upgrades, the eligible customer is given 30 days to respond, which is more than a sufficient time.

Sections 33.2 and 34.4

Rehearing Requests

TAPS asserts that the Commission cannot shunt aside the need for ongoing revenue crediting to reduce transmission charges as a rate issue, while allowing monthly redispatch costs to be collected monthly in charges under the tariff. It contends that the Commission must require revenues to be shared on an ongoing, load-ratio basis.

Commission Conclusion

As discussed above, redispatch of all Network Resources and the transmission provider's own resources is only to be performed to maintain the reliability of the transmission system, not for economic reasons. As a result, the frequency of redispatch charges being assessed to network customers is expected to be infrequent. In addition, the Commission is according substantial flexibility to public utilities to propose appropriate pricing terms in their compliance tariff, which includes the treatment of revenue credits. As mentioned above, there are several methods that utilities can use to properly reflect a benefit from non-firm transmission service to firm transmission customers. We do not believe it appropriate to mandate a specific method, such as automatic monthly flow through of revenue credits, at this time. However, TAPS may pursue this issue when utilities file their compliance rates or subsequent 205 rate filings.

Section 34.3

Rehearing Requests

Several utilities assert that because the monthly transmission system load is composed in part of the contract demands of all firm point-to-point transmission customers and under the Rule the charge for firm point-to-point service may be derived by dividing the transmission cost of service by the sum of the transmission provider's 12 monthly peak firm transmission loads, the transmission provider is prevented from recovering its entire cost of service.[430]

Maine Public Service states that parties should be allowed to argue on a case-by-case basis that firm transmission revenues should be credited instead of including the demands in the denominator (it indicates that this issue is pending in Docket No. ER95–836). It asserts that the revenue credit method would prevent transmission providers that offered discounts from unjustly being penalized for that decision and is the only method that permits utilities to have an opportunity to recover their costs. It adds that the Commission established procedures to keep gas pipelines whole in this same situation.

Commission Conclusion

While the Commission established one method of calculating load ratios and allocating costs in Order No. 888,[431] utilities are free to propose alternative pricing methodologies in a section 205 filing consistent with the Commission's Transmission Pricing Policy Statement.[432] We note, however, such utilities will have the burden of demonstrating that these methods would not result in over-collections of their revenue requirement.

Section 34.4

Rehearing Requests

TDU Systems asks the Commission to clarify, as a matter of comparability, that any mechanism proposed by a transmission provider to collect charges based on opportunity costs associated with redispatch must provide for the collection of other customers' like costs and payments to those customers.

Commission Conclusion

This issue is addressed in Section IV.G.1.e. (Opportunity Cost Pricing).

Schedules 7 and 8

Rehearing Requests

TAPS asks the Commission to clarify that these schedules do not approve ''heightened'' charges for short-term services.

Commission Conclusion

The Commission did not specify transmission rates for any tariff services in Order No. 888. The rates for long-term firm transmission, short-term firm transmission and non-firm transmission services are to be proposed by the transmission provider, as listed on Tariff schedules 7 and 8, and filed with the Commission. TAPS' argument regarding ''heightened'' charges for these services is therefore premature. TAPS is free to raise this concern at such time as utilities file their proposed transmission rates.

Attachment G

Rehearing Requests

Santa Clara and Redding ask the Commission to modify Attachment G so that, where interconnection/operational standards are in place and working effectively, additional standards are not imposed simply as a result of switching to the pro forma tariff from its current interconnection service.

Commission Conclusion

The pro forma tariff does not specifically require that the network operating agreement between the transmission provider and network customer must be a new agreement. However, the network operating agreement is expected to be a highly detailed agreement between the transmission provider and network customer establishing the integration of the network customer within the transmission provider's transmission system. Existing agreements between the customer and transmission provider may not provide all of the information required or make all of the technical arrangements required under the pro

[430] *E.g.*, Utilities For Improved Transition, Florida Power Corp, VEPCO (asserts that rates for firm point-to-point service should be developed in the same way).

[431] FERC Stats. & Regs. at 31,738; *mimeo* at 304.

[432] *See* FERC Stats. & Regs. at 31,768–70; *mimeo* at 394–99.

forma tariff (*e.g.*, redispatch and ancillary services information and arrangements.) Nevertheless, to the extent the transmission customer is currently receiving network integration transmission service or similar service and its present interconnection agreement fully comports with the requirements of the terms and conditions of the tariff including the informational requirements specified in tariff sections 33 and 35, then the present interconnection/operations agreement can be substituted for a network operating agreement or modified appropriately.

9. Miscellaneous Tariff Administrative Changes

Due to administrative oversight, certain tariff sections require minor corrections or modifications. Because of the administrative nature of these changes, we believe that no further discussion is needed.

Section 12.1 Internal Dispute Resolution Procedures

—Changes ''Transmission Service'' to ''transmission service''

Section 13.6 Curtailment of Firm Transmission Service

—Changes the description regarding curtailment of multiple transactions to:

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.

10. Pro Forma Tariff Compliance Filings

Absent a waiver, all public utilities must submit, no later than July 14, 1997, a compliance filing that reflects the tariff changes set forth in this order on rehearing.[433]

A conforming pro forma tariff, containing all the revisions and clarifications contained in this order on rehearing, is attached as Appendix B. In addition, an electronic version of the conforming pro forma tariff will be made available on the Commission's electronic bulletin board service (Commission Issuance Posting System (CIPS)) in redline/strikeout form in WordPerfect 5.1 format.

H. Implementation

In the Final Rule, the Commission set forth the details of the implementation procedures and included special implementation requirements for coordination arrangements (power pools, public utility holding companies, and bilateral coordination arrangements).[434]

The Revised Procedures

The Commission adopted slightly different implementation procedures for Group 1 public utilities (tendered for filing open access tariffs before the date of issuance of the Rule) and for Group 2 public utilities (did not tender for filing open access tariffs before the date of issuance of the Rule).

1. Group 1 Public Utilities

In the Final Rule, the Commission required Group 1 public utilities, within 60 days following publication of the Final Rule in the Federal Register, to make section 206 compliance filings that contain the non-rate terms and conditions set forth in the Final Rule pro forma tariff and identify any terms and conditions that reflect regional practices, as discussed below.[435]

As to rates, the Commission noted that a transmission tariff rate is already in effect for all Group 1 public utilities, except for the few with recently-tendered applications that have not yet been accepted for filing.

The Commission noted, however, that if a Group 1 public utility determined that certain rate changes are necessitated by the revised non-rate terms and conditions, it may file a new rate proposal under FPA section 205. The Commission indicated that such filings must be ''conforming'' [436] under the Transmission Pricing Policy Statement and must be made no later than 60 days after publication of the Final Rule in the Federal Register and intervenors may raise any concerns with the filings within 15 days after such filings. [437] The Commission imposed a blanket suspension for any filings by Group 1 public utilities proposing rate changes necessitated by the new non-rate terms and conditions. The Commission further indicated that these rates will go into effect, subject to refund, 60 days after publication of this Rule in the Federal Register (the same day on which the non-rate terms and conditions of the Final Rule pro forma tariff go into effect).

2. Group 2 Public Utilities

In the Final Rule, the Commission indicated that Group 2 public utilities will be treated the same as Group 1 public utilities with regard to non-rate terms and conditions, but will be treated slightly differently from Group 1 as to rates, since Group 2 utilities have not filed any proposed rates.[438] The Commission required these utilities to *either:* (i) within 60 days following publication of the Final Rule in the Federal Register, make section 206 compliance filings that contain the non-rate terms and conditions set forth in the Final Rule pro forma tariff and identify any terms and conditions that reflect regional practices, as discussed below; and (ii) within 60 days following publication of the Final Rule in the Federal Register, make section 205 filings to propose rates for the services provided for in the tariff, including ancillary services; *or* (iii) make a ''good faith'' request for waiver. The Commission added that the rates must meet the standards for conforming proposals in the Commission's Transmission Pricing Policy Statement and comply with the guidance concerning ancillary services set forth in this order.

The Commission explained that intervenors may raise any concerns with these filings within 15 days after the filing.[439] The Commission imposed a blanket suspension for all such rate filings and indicated that they will go into effect, subject to refund, 60 days after the publication of this Rule in the Federal Register (the same day on which the terms and conditions of the compliance tariffs go into effect).

[433] To the extent a public utility has been granted a waiver of the Order No. 888 tariff filing requirements (or a non-public utility for reciprocity purposes), it need not submit a request for a separate waiver of the requirements of this order on rehearing.

[434] FERC Stats. & Regs. at 31,768–70; *mimeo* at 393–400.

[435] FERC Stats. & Regs. at 31,768–69; *mimeo* at 394–96.

[436] As described in the Transmission Pricing Policy Statement, a ''conforming'' proposal is one that meets the traditional revenue requirement and reflects comparability. FERC Stats. & Regs. ¶ 31,005 at 31,141.

[437] Given the brief comment period on the compliance filings, the Commission required public utilities to serve copies of their compliance filings (via overnight delivery) on: all participants in their current open access rate proceedings (if applicable); all customers that have taken wholesale transmission service from the utility after the date of issuance of the Open Access NOPR; and the state agencies that regulate public utilities in the states of those participants and customers. By order issued July 2, 1996, the Commission extended the comment period from 15 days to 30 days.

[438] FERC Stats. & Regs. at 31,769; *mimeo* at 396–97.

[439] The Commission held that Group 2 public utilities must serve a copy of their filings (via overnight delivery) on all customers that have taken wholesale transmission service from them since March 29, 1995 (the date of issuance of the Open Access NOPR) and on the state agencies that regulate public utilities in the states where those customers are located. By order issued July 2, 1996, the Commission extended the comment period from 15 days to 30 days.

3. Clarification Regarding Terms and Conditions Reflecting Regional Practices

In the Final Rule, the Commission explained that it had built a degree of flexibility into the tariffs to accommodate regional and other differences. [440] It explained that certain non-rate Final Rule pro forma tariff provisions specifically allow utilities either to follow the terms of the provision or to use alternatives that are reasonable, generally accepted in the region, and consistently adhered to by the transmission provider (*e.g.*, time deadlines for scheduling changes, time deadlines for determining available capacity). In addition, it explained that other tariff provisions require utilities to follow Good Utility Practice (section 1.14 of the Final Rule pro forma tariff).

4. Future Filings

In the Final Rule, the Commission indicated that once the compliance tariff and conforming rates go into effect, which would be 60 days after publication of the Rule in the Federal Register, a public utility (either Group 1 or Group 2) may file pursuant to section 205 a tariff with terms and conditions that differ from those set forth in this Rule, provided that, among other things, it demonstrates that such terms and conditions are consistent with, or superior to, those in the compliance tariff.[441] However, the Commission emphasized that the public utility may not seek to litigate fundamental terms and conditions set forth in the Final Rule. In addition, the Commission explained that the public utility may file whatever rates it believes are appropriate, consistent with the Transmission Pricing Policy Statement.

5. Waiver

In the Final Rule, the Commission found that it is reasonable to permit certain public utilities for good cause shown to file, within 60 days after the Rule is published in the Federal Register, requests for waiver from some or all of the requirements of this Rule.[442] The Commission explained that the filing of a request in good faith for a waiver from the requirement to file an open access tariff will eliminate the requirement that such public utility make a compliance filing unless thereafter ordered by the Commission to do so. The Commission emphasized, however, that it will not exempt such public utility from providing, upon request, transmission services consistent with the requirements of the Final Rule.

Rehearing Requests

Wisconsin Municipals asserts that the Commission should ''require utilities (if requested by their customers) to honor the settlements to which they have agreed and to file the *pro forma* tariff, modified to incorporate settlement provisions that exceed the minimum provisions of the *pro forma* tariff, as their implementational filing.'' Alternatively, it asks that the Commission ''require parties with settlements to make a Section 205 filing one day following their implementation filing, change any rates, terms and conditions in the *pro forma* tariff as necessary to incorporate any superior provisions from their settlement tariffs into the *pro forma* tariff, and seek any waivers necessary to make the settlement tariff effective immediately.'' (Wisconsin Municipals at 7–10).

Blue Ridge requests rehearing of the ''unbalanced tariff implementation process that rolls over the due process rights of transmission customers.'' It asserts that utilities should not have the right to file a '''Good Utility Practices,' blank check variance for regional practices in the compliance docket.'' (Blue Ridge at 33–35). Blue Ridge further requests that Group 1 utilities file compliance tariffs in the same docket as their pending open access dockets and asks that subsequent changes be in a separate docket as a new general rate case. Blue Ridge also states that the Commission should explicitly mention that customers have the right to file section 206 requests to change the tariffs.

Indianapolis P&L argues that the pricing requirements are unjust, unreasonable, unlawful, confiscatory and an abuse of discretion as to Indianapolis P&L. It asserts that its rates are not based on embedded, original cost, but, as a matter of Indiana law, its utility property is valued at the ''fair value,'' which exceeds the embedded original cost of such property. It declares that it is impossible for Indianapolis P&L to comply with both the comparability requirement and the requirement that transmission rates be based on original cost. It states that the requirement to provide transmission service and generation-based ancillary services at rates based on original cost is not comparable to Indianapolis P&L's own use of its assets. Accordingly, it argues that the Commission should allow Indianapolis P&L to set its initial open access rates on a fair value, long-run marginal cost basis. Alternatively, it states that the Commission could grant Indianapolis P&L a waiver from the requirements of the Open Access Rule.

Indianapolis P&L further argues that the imposition of an obligation to enlarge generation to provide ancillary services is beyond the Commission's statutory authority. It explains that Indianapolis P&L is an incidental transmission owner and a relatively small public utility and asks that the Commission grant it waiver from the requirements of open access and OASIS. In deciding whether to grant a waiver, it asserts that the Commission should also consider system size and configuration, the amount of wholesale revenues or MWH sales, or the availability of competing transmission paths.

Union Electric argues that the final rules violate procedural due process and that the implementation schedule is unrealistically ambitious. It argues that where the final rules call for changes from the NOPRs that could not be reasonably anticipated, they amount to deprivation of due process and rights to fairness in the administrative process. Indeed, it points out, the Commission itself has not even completed its promulgation of the OASIS Final Rule. Union Electric is concerned that it has not had an adequate time to comply with and comment on the rules.

Commission Conclusion

Wisconsin Municipals has misinterpreted the Commission's findings in Order No. 888, and thus its concerns are without merit. While it is true that Order No. 888 requires all public utilities to make compliance filings containing the non-price terms and conditions set forth in the Final Rule pro forma tariff,[443] Order No. 888 also states that ''we are not abrogating existing requirements and transmission contracts generically. * * *'' [444] In short, the Commission is not requiring (or even generically allowing) the abrogation of existing transmission contracts, but is only requiring that jurisdictional transmission providers must also offer transmission service under the Final Rule pro forma tariff *in addition to* whatever commitments the provider will continue to have under its existing contracts. [445]

As to Wisconsin Municipals' assertions that prior individual settlement provisions may exceed the

[440] FERC Stats. & Regs. at 31,769–70; *mimeo* at 397–98.

[441] FERC Stats. & Regs. at 31,770; *mimeo* at 398–99.

[442] FERC Stats. & Regs. at 31,770; *mimeo* at 399–400.

[443] FERC Stats. & Regs. at 31,768–69; *mimeo* at 394–96.

[444] FERC Stats. & Regs. at 31,665; *mimeo* at 87–88.

[445] *See also* discussion of prior settlements in Section IV.D.1.c.(2) (Energy Imbalance Bandwidth).

minimum provisions of the pro forma tariff, the Commission believes that such arguments should be addressed on a case-by-case basis. [446]

Two additional points are pertinent. First, we note that although we are not generically abrogating existing transmission contracts, utilities retain whatever existing rights they had to propose unilateral changes under section 205 of the FPA if they want to convert a customer to service under the tariff, and customers retain their section 206 right to seek reformation of existing transmission contracts if they are unjust, unreasonable, unduly discriminatory or preferential. Second, where a utility has treated similarly-situated customers differently—serving one under a more favorable bilateral contract and another under a less favorable tariff provision—traditional undue discrimination remedies may be available.

We deny Blue Ridge's rehearing requests because the Commission does not intend to assume the regulatory responsibility of identifying in the first instance all of the regional practices around the country that could (and should) properly be reflected in the compliance tariffs. Transmission customers opposed to deviations related to regional practices not only had the opportunity to protest the compliance filings when they were tendered, [447] but these customers also have the right to file section 206 requests to change these tariffs at any time. In addition, Blue Ridge's request that customers be given 45 days to respond to compliance filings instead of 15 days is moot. In an order issued July 2, 1996,[448] we took three actions to address this concern: (1) we gave entities 30 days, instead of 15 days, to respond to Order No. 888 compliance filings; (2) we agreed to post an electronic version of all Order No. 888 compliance filings on the Commission's Electronic Bulletin Board; and (3) we required all public utilities making a compliance filing to also serve a copy of their filing on electronic diskette to any eligible customer or state regulatory agency requesting a copy. We believe that these actions not only provided all interested parties with access to the compliance filings more quickly, but also provided these parties sufficient time to analyze the information once they received it.[449] Moreover, the time periods provided for making and responding to Order No. 888 compliance filings have expired.

With regard to Blue Ridge's first clarification request, we provide the following guidance. Utilities that had pending open access filings at the time that the Final Rule was implemented had the non-price terms and conditions of those pending tariffs superseded by their Order No. 888 compliance filings. Any customer concerns about the non-rate tariff terms and conditions in the compliance filing should be raised in the compliance docket, and any future customer concerns should be raised in a separate, future section 206 complaint filed by the customer.

Furthermore, we reject Indianapolis P&L's rate issue because, if this utility believes that it operates under special circumstances that require it to use ''non-conforming'' pricing methods, it is free to file such a proposal under section 205. The merits of Indianapolis P&L's arguments are more appropriately addressed in such a section 205 proceeding. The Commission will not alter its generic policy (which is the subject of this rulemaking) merely to address the particular needs of one party.

In addition, with regard to both of Indianapolis P&L's concerns, we note that pursuant to the Commission's July 2 Order, the Commission indicated that it would not address waiver requests in a generic proceeding and that parties would have to file such requests separately for separate docketing. We further note that Indianapolis P&L filed a separate waiver request on July 9, 1996, which was docketed as OA96–81.[450]

We also reject Union Electric's argument that the final rules violate procedural due process. Union Electric has had every opportunity to raise arguments with regard to every step in the Commission's derivation and implementation of the final rules. Moreover, with regard to Union Electric's claim that it was given an inadequate amount of time to comprehend and implement the final rules, we note that virtually every public utility, including Union Electric, complied with the Open Access Rule on a timely basis, and there have been very few complaints that the rules are hard to comprehend.

I. Federal and State Jurisdiction: Transmission/Local Distribution

In the Final Rule, the Commission explained that after reviewing the extensive analysis of the FPA, legislative history, and case law contained in both the initial Stranded Cost NOPR and in the Open Access NOPR, and the comments received on that analysis, it reaffirmed its assertion of jurisdiction over the transmission component of an unbundled interstate retail wheeling transaction.[451] The Commission also reaffirmed and clarified its determinations regarding the tests to be used to determine what constitute Commission-jurisdictional transmission facilities and what constitute state-jurisdictional local distribution facilities in situations involving unbundled wholesale wheeling and unbundled retail wheeling.

The Commission also explained that where states unbundle retail sales, it will give deference to their determinations as to which facilities are transmission and which are local distribution, provided that the states, in making such determinations, apply the seven criteria discussed in the NOPR and reaffirmed by the Commission. In addition, the Commission clarified that there is an element of local distribution service in any unbundled retail transaction, and further clarified other aspects of its jurisdictional ruling to preserve state jurisdiction over matters that are of local concern and will remain subject to state jurisdiction if retail unbundling occurs.

The Commission reaffirmed its legal determination that if unbundled retail transmission in interstate commerce occurs voluntarily by a public utility or as a result of a state retail access program, this Commission has exclusive jurisdiction over the rates, terms, and conditions of such transmission. The Commission found compelling the fact that section 201 of the FPA, *on its face*, gives the Commission jurisdiction over transmission in interstate commerce (by public utilities) without qualification.

The Commission further explained that when a retail transaction is broken into two or more products that are sold separately, the jurisdictional lines change. In this situation, the Commission emphasized that the state clearly retains jurisdiction over the sale of the power, but the unbundled

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[446] *See* IES Utilities, Inc., *et al.*, 78 FERC ¶ 61,023 (1997).

[447] We do note that most of these concerns have been addressed in our orders dealing with the compliance filings on non-rate terms and conditions. *See, e.g.*, Atlantic City Electric Company, *et al.*, 77 FERC ¶ 61,144 (1996); Allegheny Power System, Inc., *et al.*, 77 FERC ¶ 61,266 (1996).

[448] 76 FERC ¶ 61,009 at 61,026–27 (1996) (July 2 Order).

[449] We also note that utilities were required in Order No. 888 to explicitly identify any regional practices in their compliance filings.

[450] By order issued September 11, 1996, the Commission denied Indianapolis P&L's requested waiver of all the requirements of Order No. 888. On October 8, 1996, Indianapolis P&L sought rehearing of that order and a stay of the requirements of Order No. 888. These pleadings are now pending before the Commission.

[451] FERC Stats. & Regs. at 31,780–85; *mimeo* at 427–42.

transmission service involves *only* the provision of ''transmission in interstate commerce'' which, under the FPA, is exclusively within the jurisdiction of the Commission.

The Commission recognized that in asserting jurisdiction over unbundled retail transmission in interstate commerce by public utilities, it was in no way asserting jurisdiction to order retail transmission directly to an ultimate consumer. It explained that its assertion of jurisdiction is that *if* unbundled retail transmission in interstate commerce by a public utility occurs voluntarily or as a result of a state retail wheeling program, the Commission has exclusive jurisdiction over the rates, terms, and conditions of such transmission and public utilities offering such transmission must comply with the FPA by filing proposed rate schedules under section 205.

The Commission further clarified that nothing in its jurisdictional determination changes historical state franchise areas or interferes with state laws governing retail marketing areas of electric utilities. It explained that while its jurisdiction cannot affect whether and to whom a retail electric service territory (marketing area) is to be granted by the state, and whether such grant is exclusive or non-exclusive, neither can state jurisdiction affect this Commission's exclusive jurisdiction over transmission in interstate commerce by public utilities.

The Commission also adopted a new section 35.27(b) as follows:

> Nothing in this part (i) shall be construed as preempting or affecting any jurisdiction a state commission or other state authority may have under applicable state and federal law, or (ii) limits the authority of a state commission in accordance with state and federal law to establish (a) competitive procedures for the acquisition of electric energy, including demand-side management, purchased at wholesale, or (b) non-discriminatory fees for the distribution of such electric energy to retail consumers for purposes established in accordance with state law.

With respect to the Commission's adoption of the Open Access NOPR's functional/technical tests for determining what facilities are Commission-jurisdictional facilities used for transmission in interstate commerce and what facilities are state-jurisdictional local distribution facilities, the Commission concluded that it could not divine a bright line for unbundled retail transmission by the public utility that previously provided bundled retail service to the end user. The Commission added that the limited case law, including *Connecticut Light & Power Company* v. *FPC (CL&P)* and *Federal Power Commission* v. *Southern California Edison Company* (the *Colton* case),[452] supports a case-by-case determination.[453] Accordingly, the Commission stated that its technical test, with its seven indicators, will permit reasoned factual determinations in individual cases.

The Commission made two clarifications regarding local distribution in the context of retail wheeling. First, it explained that even if its technical test for local distribution facilities were to identify no local distribution facilities for a specific transaction, states have authority over the *service* of delivering electric energy to end users. Second, the Commission explained that through their jurisdiction over retail delivery services, states have authority not only to assess retail stranded costs but also to assess charges for so-called stranded benefits, such as low-income assistance and demand-side management.

Thus, under this interpretation of state/federal jurisdiction, the Commission explained, customers have no incentive to structure a purchase so as to avoid using identifiable local distribution facilities in order to bypass state jurisdiction and thus avoid being assessed charges for stranded costs and benefits.

The Commission further determined that it is appropriate to provide deference to state commission recommendations regarding certain transmission/local distribution matters that arise when retail wheeling occurs.

In instances of unbundled retail wheeling that occurs as a result of a state retail access program, the Commission indicated that it will defer to recommendations by state regulatory authorities concerning where to draw the jurisdictional line under the Commission's technical test for local distribution facilities, and how to allocate costs for such facilities to be included in rates, provided that such recommendations are consistent with the essential elements of the Final Rule.[454] Moreover, the Commission indicated that it will consider jurisdictional recommendations by states that take into account other technical factors that the state believes are appropriate in light of historical uses of particular facilities.

As a means of facilitating jurisdictional line-drawing, the Commission stated that it will entertain proposals by public utilities, filed under section 205 of the FPA, containing classifications and/or cost allocations for transmission and local distribution facilities. However, the Commission explained that, as a prerequisite to filing transmission/local distribution facility classifications and/or cost allocations with the Commission, utilities must consult with their state regulatory authorities. If the utility's classifications and/or cost allocations are supported by the state regulatory authorities and are consistent with the principles established in the Final Rule, the Commission indicated that it will defer to such classifications and/or cost allocations.

Furthermore, the Commission stated that deference to state commissions with regard to rates, terms, and conditions may be appropriate in some circumstances. The Commission explained that when unbundled retail wheeling in interstate commerce occurs, the transaction has two components for jurisdictional purposes—a transmission component and a local distribution component. It again emphasized that the Commission has jurisdiction over facilities used for the transmission component of the transaction, and the state has jurisdiction over facilities used for the local distribution component. Thus, the Commission stated, the rates, terms and conditions of unbundled retail transmission by a public utility must be filed at the Commission. However, the Commission added, if the unbundled retail wheeling occurs as part of a state retail access program, it may be appropriate to have a separate retail transmission tariff[455] to accommodate the design and special needs of such programs. In such situations, the Commission indicated that it will defer to state requests for variations from the FERC wholesale tariff to meet these local concerns, so long as the separate retail tariff is consistent with the Commission's open access policies and comparability principles reflected in the tariff prescribed by the Final Rule. In addition, the Commission indicated that

[452] 324 U.S. 515 (1945) (*CL&P*); 376 U.S. 205 (1964) (*Colton*).

[453] The Commission included a detailed legal analysis in Appendix G to Order No. 888. The Commission explained that it was particularly persuaded by the Supreme Court's statement that whether facilities are used in local distribution is a question of fact to be decided by the Commission as an original matter. *See CL&P*, 324 U.S. at 534–35).

[454] In order to give such deference, the Commission noted its expectation that state regulators will specifically evaluate the seven indicators and any other relevant facts and make recommendations consistent with the essential elements of the Rule.

[455] The Commission noted that such a tariff could be different from the tariff that applies to wholesale customers, but that such tariff would still be filed with the Commission under FPA section 205.

the rates must be consistent with its Transmission Pricing Policy Statement, and the guidance set forth in Order No. 888 concerning ancillary services.[456]

The Commission also expressed concern, just as it did with buy-sell arrangements in the gas industry, that buy-sell arrangements can be used by parties to obfuscate the true transactions taking place and thereby allow parties to circumvent Commission regulation of transmission in interstate commerce. Thus, the Commission reaffirmed its conclusion that it has jurisdiction over the interstate transmission component of transactions in which an end user arranges for the purchase of generation from a third-party. Moreover, the Commission indicated that it will address these transactions on a case-by-case basis.

Rehearing Requests

Oppose Commission Assertion of Jurisdiction Over Unbundled Retail Transmission

Several state commissions indicate that, recognizing that the case law is not dispositive concerning the question of unbundled retail transmission services (either because the cases do not involve the transmission of power to retail customers or ''fence off'' local distribution from federal regulation), at least one court (*Wisconsin-Michigan Power Company* v. *FPC,* 197 F.2d 472 (7th Cir. 1952), *cert. denied,* 345 U.S. 934 (1953)) explicitly applied the wholesale/retail distinction to distinguish transmission and local distribution services.[457] Thus, they argue, the Commission should apply the wholesale versus retail analysis to the question of unbundled retail transmission.

IL Com asserts that retail transmission by a public utility directly to an end user has always (even before the FPA was enacted) been subject to regulation by the states. It contends that no change in law has occurred which justifies the Commission's claim of expanded jurisdiction. Moreover, it disagrees with the Commission's conclusion that the unbundled delivery by the previous public utility generation supplier directly to an end user is in interstate commerce. It argues that the FPA was never intended to disturb the jurisdiction of state regulators that existed prior to its passage and that retail transmission of electric energy by a public utility to an end user was under state jurisdiction before the *Attleboro* decision and has remained under state jurisdiction in the over sixty years following *Attleboro.* Even after unbundling, according to IL Com, transmission to a retail customer still involves a retail sale of transmission.

NARUC and VA Com assert that the legislative history provides little support for the Commission's conclusion that the act of unbundling generation from delivery serves to shift jurisdiction from a state commission to the Commission. If anything, they contend, the jurisdictional structure of the FPA is predicated on the distinction between retail and wholesale transactions, not bundled and unbundled services. They assert that the Commission should conclude that the rates, terms and conditions of service for delivery of power by a utility to an end-use customer are subject to the jurisdiction of the state commission regulating the utility, regardless of the identity of the party generating or reselling the power or the facilities used to transport the power.

NARUC asserts that the Commission did not address a point raised in NARUC's reply comments as to how the removal of generation serves to unbundle the retail delivery function into separate transmission and distribution services. It maintains that the Commission simply assumes that a resulting transmission transaction is created when power is sold to a retail consumer by someone other than the utility delivering the power.[458]

MI & NH Coms ask the Commission to vacate those portions of the Rule that find that the Commission has jurisdiction over the transmission component of an unbundled retail sale in a local retail wheeling transaction. They assert that the Commission should confine its activity to wholesale transactions or those interstate transactions that do not implicate matters of local concern. They argue that the dual federal/state regulatory scheme establishes that Congress' intent is that state regulation of retail wheeling *is not* preempted by federal law as established in FPA section 201. They oppose unnecessary federal intrusion into local matters under a one-size-fits-all approach and assert that the retail wheeling initiatives in New Hampshire and Michigan are tailored to the unique utility environment in each state.

Central Illinois Light argues that unbundling of retail electric service does not change the states' longstanding jurisdiction over retail electric service and local distribution, even when that service involves the use of transmission in interstate commerce. It asserts that 201(b)(1) (''transmission of electric energy in interstate commerce'') cannot be read in a vacuum.

MN DPS & MN Com and OH Com assert that the Commission should have no role in the regulation of retail services, be they bundled or unbundled. They argue that, in refusing to grant the Commission authority over retail wheeling, Congress left jurisdiction over retail electric service to the states. They conclude that the Final Rule contains insufficient legal and/or policy justification for the Commission's assertion of jurisdiction over unbundled retail transmission services.

MN DPS & MN Com assert: ''FERC bases its usurpation of state authority over retail transmission rates on its claim that balkanization would occur without the assertion of FERC authority. Therefore, the parties are entitled to rehearing so that this essential issue can be further analyzed.'' (MN DPS & MN Com at 1–3).

FL Com argues that the Commission has not justified why the act of unbundling prices expands the Commission's jurisdiction into retail marketing areas. It argues that Section 212(g) of the FPA has the effect of prohibiting the Commission from usurping existing state jurisdiction over retail transmission service, whether bundled or unbundled. According to FL Com, FERC's jurisdiction over transmission terminates at the territorial boundary of each electric utility in Florida. It supports wheeling in jurisdiction for state commissions and wheeling out and wheeling through jurisdiction for the Commission.

IN Com opposes federalization of retail wheeling transactions within a state's boundaries as contrary to the FPA's legislative history and case law.

NJ BPU asserts that by claiming jurisdiction over unbundled retail transmission, the Commission is creating a disincentive for states to implement retail access because, by ordering retail access, the states may be relinquishing their jurisdiction over unbundled retail transmission terms and conditions—jurisdiction that they would maintain under a bundled scenario.[459] PA Com argues that the Commission does not have the authority

[456] In applying the principles of the Final Rule to retail transmission tariffs, the Commission emphasized that it clearly cannot order retail wheeling directly to an ultimate consumer. (citing FPA section 212(h)).

[457] E.g., NARUC, WI Com, WY Com.

[458] *See also* IA Com (use of a utility's transmission system to serve its own retail customers is a bundled part of the retail sale transaction, which supports a simpler jurisdictional test holding that a movement of power by the last utility in any chain of delivery to a retail customer is a distribution transaction).

[459] *See also* PA Com.

to order retail wheeling and that the jurisdictional formula is challengeable on engineering and legal grounds. It concludes that the Commission does not have jurisdiction over unbundled interstate retail transmission service. PA Com notes that the 1996 House and Senate hearings have raised the question whether the Commission has the statutory authority to restructure the electric industry. PA Com questions the Commission's definition of the ''traditional tasks of state and federal regulators'' on the basis of section 201(b) of the FPA, the Supremacy Clause, and the Tenth Amendment of the U.S. Constitution.

Support Broader Assertion of Jurisdiction by the Commission Over Retail Wheeling

NY Utilities declare that the Commission has jurisdiction over retail wheeling from the source to the load, but does not have jurisdiction over transmission in bundled retail service. They assert that the Commission's reliance on state jurisdictional local distribution as a predicate to abstain from allowing retail wheeling stranded cost recovery is without foundation. They further assert that a unique element that sets local distribution apart from transmission is not the size of the facility or the length of travel, but that transportation is bundled with a retail sale. According to NY Utilities, the plain meaning of the FPA shows that local distribution is bundled retail service. They claim that the legislative history, to the extent necessary, and court cases support FERC jurisdiction over all aspects of retail wheeling, but makes clear that the Commission cannot regulate bundled retail service. They add that the NGA also demonstrates that local distribution means bundled retail service.

Commission Conclusion

In concluding that this Commission has exclusive jurisdiction over the rates, terms and conditions of unbundled retail transmission by public utilities in interstate commerce, the Commission in Order No. 888 thoroughly examined the statutory language of the FPA and its legislative history, and relevant FPA and NGA case law. While the state commissions on rehearing would like us to draw a bright line that gives them, to varying degrees, jurisdiction over retail interstate transmission by public utilities, no party on rehearing has raised any legislative history or case law that was not previously considered and that would support the proposition that states have jurisdiction over any unbundled transmission in interstate commerce. As explained below, we reaffirm our jurisdictional interpretation on rehearing and believe that it is supported by the recent decision in *United Distribution Companies* v. *FERC*.[460]

Many of the rehearing arguments focus on the fact that states historically (even prior to the FPA) regulated retail transmission insofar as it was a component of bundled electric service to an end user, and they argue that by asserting jurisdiction over unbundled retail transmission, the Commission is somehow ''taking away'' jurisdiction the states previously had. The flaw in these arguments is their inherent assumption that jurisdiction over transmission service turns upon the question of whether the transmission service is being provided for ''wholesale'' or ''retail'' power sales. That is not the case. The question of jurisdiction rather turns upon the extent of the Commission's exclusive jurisdiction over transmission in interstate commerce under the FPA. The fact that states historically regulated most retail transmission service as a part of a bundled retail power sale is not the result of a legal requirement; it is the practical result of the way electricity has historically been bought and sold. However, the shape of power sales transactions is rapidly changing. Rather than claiming ''new'' jurisdiction, the Commission is applying the same statutory framework to a business environment in which, as discussed below, retail sales and transmission service are provided in separate transactions.

In the past, retails ales occurred almost exclusively on a bundled basis (*i.e.*, the same entity provided a delivered product called electric energy and transmission was part and parcel of that product). The FPA clearly reserves the right to regulate retail sales of electric energy to the states. As we explained in the Final Rule, however, in today's markets, and increasingly in the future as more states adopt retail wheeling programs, retail transactions are being broken into products that are being sold separately: transmission and generation. Moreover, these products are being sold increasingly by two or more different entities. For example, a transaction may involve transmission service from one or more transmission providers who move power from a distant generation supplier, over the interstate transmission grid, to an end user. Because these types of products and transactions were not prevalent in the past, the jurisdictional issue before us did not arise and, contrary to IL Com's argument, the Commission cannot be viewed as ''disturbing'' the jurisdiction of state regulators prior to and after the *Attleboro* case.[461]

As we also explained in the Final Rule, the legislative history of the FPA and the relevant case law similarly reflect the historical market structure in which electricity and transmission generally were bought on a bundled basis.[462] Today's unbundled world simply was not contemplated and the cases do not resolve dispositively this jurisdictional issue. The case law focuses primarily on the bright line between wholesale sales and retail sales of *energy*, and transmission in interstate as opposed to intrastate commerce. It does not address unbundled retail interstate transmission.[463] We therefore have interpreted the case law in light of changed circumstances and have relied in the first instance on the plain wording of the statute. We find compelling that section 201 of the FPA, on its face, gives the Commission jurisdiction over transmission in interstate commerce without qualification; unlike our jurisdiction over sales of electric energy, which section 201 specifically limits to sales at wholesale, the statute does not limit our transmission jurisdiction over public utilities to wholesale transmission.

Since the time Order No. 888 issued, the D.C. Circuit has addressed a similar issue in interpreting section 1(b) of the NGA, the provision that parallels section 201(b) of the FPA. Under section 1(b), the Commission's jurisdiction does not apply ''to the local distribution of natural gas or to the facilities used for such distribution.'' Similarly, under section 201(b) of the FPA, the Commission shall not have jurisdiction, except as specifically provided, ''over

[460] 88 F.3d 1105, 1152–53 (1996) (*United Distribution Companies*).

[461] Public Utilities Commission v. Attleboro Steam & Electric Co., 273 U.S. 83 (1927).

[462] The case law is addressed extensively in Appendix G to the Final Rule and will not be repeated here.

[463] On rehearing, several parties argue that at least one court case, Wisconsin-Michigan Power Co. v. FPC, 197 F.2d 472 (7th Cir. 1952), *cert. denied*, 345 U.S. 934 (1953) explicitly applied the wholesale/retail distinction to distinguish transmission and local distribution services. The Commission discussed this case in detail in Appendix G to the Final Rule, FERC Stats. & Regs. at 31,974–75; *mimeo* at 22–25. As we stated there, the court's interpretation of the legislative history of the FPA was at odds with both the plain words of the statute as well as the language of the House Report on the FPA (H.R. Rep. No. 1318 at 27). It also did not mention the Senate Report on the FPA, which clearly recognized jurisdiction over all interstate transmission lines, whether or not a sale of energy is carried by those lines (S. Rep. No. 621 at 48). We therefore reject arguments that this single case is in any way dispositive of the issue before us.

facilities used for the generation of electric energy or over facilities used in local distribution * * *'' In responding to arguments regarding the scope of state authority over ''local distribution'' of natural gas, the court distinguished between bundled and unbundled sales:

States have been—and are still—permitted to regulate LDCs' bundled sales of natural gas to end-users because those transactions include transportation over local mains and the retail sales of gas. In contrast, states have *never* regulated the terms and conditions of interstate pipeline transportation. When the gas sales element is severed—*i.e.,* unbundled—from the transactions, FERC retains jurisdiction over the *interstate transportation* component.'' [United Distribution Companies, 88 F.3d at 1153 (footnote omitted) (emphasis in original).]

The court's reasoning is also applicable to and supports our jurisdictional determination in Order No. 888.

Several state commissions point to section 212(h) of the FPA and argue that Congress, in refusing to grant the Commission authority to order retail wheeling, left all jurisdiction over retail transmission to the states. We disagree. What Congress did in section 212(h) was to prohibit us from *ordering* transmission directly to an ultimate consumer. We readily recognize and respect this prohibition. However, the ability to order retail wheeling is a separate issue from whether we have jurisdiction over the rates, terms and conditions of retail wheeling in interstate commerce that is ordered by a state or that is provided voluntarily. Congress, in enacting section 212(h), did nothing to modify our jurisdiction under sections 201, 205 and 206 over the rates, terms and conditions of interstate transmission by public utilities.

Similarly, we reject FL Com's arguments that section 212(g) of the FPA prohibits the Commission from asserting any jurisdiction over unbundled retail transmission. Section 212(g) prohibits the Commission from issuing an order that is inconsistent with any state law that governs retail marketing areas of electric utilities. As we stated in the Final Rule, while our jurisdiction cannot affect whether and to whom a retail electric service territory (marketing area) is to be granted by the state, and whether such grant is exclusive or non-exclusive, neither can state jurisdiction affect this Commission's exclusive jurisdiction over the rates, terms and conditions of transmission in interstate commerce by public utilities. We also reject arguments by the FL Com that this Commission's jurisdiction over transmission terminates at the territorial boundary of each electric utility in Florida. This argument is flatly contrary to the longstanding interpretation of the FPA by the United States Supreme Court.[464]

Commission's Seven Factor Test

IL Com argues that the Commission should withdraw its technical test. It contends that retail wheeling jurisdiction should follow function and that the function served by public utility facilities in providing retail service does not change upon the unbundling of service to retail customers. According to IL Com, Commission jurisdiction would extend to the service of delivering electric energy by a public utility to wholesale customers, regardless of the nature and extent of the public utility's facilities used to make that delivery. Similarly, it asserts, state jurisdiction would extend to the service of delivering electric energy by a public utility directly to retail customers, regardless of the nature and extent of the public utility's facilities used to make that delivery.

NARUC argues that the seven-factor test does not result in the bright line discussed in *FPC* v. *Southern California Edison Company,* 376 U.S. 205 (1964). The facility-by-facility categorization of utility systems on a company-specific basis, it asserts, is hardly consistent with the Court's decision to make case-by-case analysis unnecessary.

OH Com asserts that the seven factors provide no useful insight into the nature of local distribution service. It adds that reliance upon technical tests to determine local distribution lacks legal foundation. It further contends that the jurisdictional bright line established by Congress focuses upon the nature of the transaction, not the functional or technical characteristics of a particular wire, in determining whose jurisdictional authority attaches to a particular transaction and facilities. It concludes that the Commission should adopt the Ohio-proposed retail marketing area ''wheeling in'' jurisdictional approach.

PA Com contends that the Commission's seven indicia are not acceptable measures of local distribution and challenges each factor.

NH & MI Coms declare that the criteria for distinguishing transmission facilities from local distribution facilities should not be limited to the seven given in the Rule, but should allow consideration of any other relevant criteria for separating local concerns from matters legitimately federal in nature.

NJ BPU argues that the engineering-driven definition does not resolve many of the hazy areas. To the extent that the seven factors do not reflect or cannot be reconciled with the particular circumstances, it contends that the states may be hamstrung in their ability to make reasoned decisions that comport with Order No. 888.[465]

Similarly, NY Com argues that five of the seven factors (1, 2, 4, 6, and 7) are not accurate when applied to large metropolitan areas and remote rural areas. It asserts that local distribution facilities are not necessarily close to retail customers and the assumption that local distribution facilities are primarily radial in character fails to account for network systems. It adds that reconsignment or transportation of power to different markets can and does occur at the local distribution level. It further adds that the presence of meters is not a discerning characteristic of where interstate transmission ends and local distribution begins; meters are frequently not part of the transmission/local distribution interface. Nor, according to NY Com, are local distribution systems necessarily of reduced voltage. Instead of the 7 criteria, NY Com argues that the Commission should adopt a functional measure of local distribution based on factors 3 and 5 (interstate transmission ends and local distribution begins where electricity flows into a comparatively restricted geographic area and does not flow back out of that area and the power is consumed in that area) and on the traditional classification of the facilities by the state regulatory body (or what the utility has traditionally classified as local distribution).

Commission Conclusion

Several parties on rehearing do not like the seven-factor technical test for local distribution facilities that was set forth in Order No. 888. That test takes into account both technical and functional characteristics of the transaction involved. The parties on rehearing propose instead a variety of bright line tests. For example, IL Com wants state jurisdiction to extend to the ''service'' of delivering electric energy to retail customers, which it would define to give it jurisdiction regardless of the

[464] *See FPC* v. *Southern California Edison Co.,* 376 U.S. 205 (1964) (*Colton* case). IN Com makes a similar argument and opposes ''federalization'' of retail wheeling within a state's boundaries. We reject this argument on the same basis.

[465] *See also* WI Com (criteria do not appropriately reflect the mixed nature of many facilities in systems that are closely integrated and the application of the criteria to the electric system in Wisconsin would supplant state jurisdiction over a large number of facilities whose primary functions are local reliability and retail service).

nature and extent of the facilities used to make the delivery. OH Com proposes that the Commission adopt a retail marketing area ''wheeling in'' jurisdictional approach which would give it jurisdiction over facilities within territorial boundaries.

In response, we do not interpret the FPA to permit us in effect to rewrite the statute to give states jurisdiction over interstate transmission services. Moreover, we reject arguments of OH Com that our seven-factor test lacks legal foundation, and arguments of NARUC that we are somehow bound to develop a bright line test. While Congress established a jurisdictional bright line between wholesale and retail sales of energy, there is no such bright line that we can divine with regard to transmission and local distribution facilities. The Supreme Court, in both *Colton* and *CL&P*,[466] has instructed us that whether facilities are used in local distribution is a question of fact to be decided by the Commission as an original matter. The seven factors will permit us to undertake this fact-specific determination.

We acknowledge the concerns raised by several state commissions that the seven-factor test does not, as NJ BPU puts it, resolve many of the hazy areas, and that there may be other factors that should be taken into account in particular situations. The seven-factor test is intended to provide sufficient flexibility to take into account unique local characteristics and historical usage of facilities used to serve retail customers. We specifically stated in the Final Rule that we will consider jurisdictional recommendations by states that take into account other technical factors that states believe are appropriate in light of historical uses of particular facilities. Moreover, we will defer to facility classifications and/or cost allocations that are supported by state regulatory authorities. For example, in the ongoing California electric utility restructuring proceeding, the Commission deferred to the State PUC's recommendations regarding the split between state jurisdictional local distribution facilities and Commission-jurisdictional transmission facilities.[467]

Oppose Transmission of Public Utility Purchases for Sale at Retail

IL Com objects to the transmission unbundling requirement if it is intended to require public utilities to take transmission services under their own FERC tariffs for purchases of power intended for distribution by the public utility to retail customers. According to IL Com, a distinction must be made between the public utility's use of its transmission system in cases in which the public utility purchases wholesale power for sale for resale, and cases in which the public utility purchases wholesale power to serve native load retail customers. It argues that the Commission cannot legally regulate, or place conditions on, the manner in which a utility uses its transmission system to make sales of electric energy at retail. It contends that the Commission must exempt public utility power purchases for sale at retail from the unbundling requirement. It recommends that the Commission insert the words ''for sale for resale'' after the word ''purchases'' in section 35.28(c)(2) and after the word ''purchase'' in section 35.28(c)(2)(i).

Commission Conclusion

The Commission rejects arguments of IL Com that if unbundled retail wheeling occurs either voluntarily or as a result of a state retail program, we cannot require the utility to take service under its own transmission tariff for sales to retail customers. This requirement is a term and condition of unbundled retail interstate transmission service and, as explained above, therefore is within our exclusive jurisdiction. Additionally, this should not in any way infringe on state retail programs or service to retail customers. Rather, it ensures that non-discriminatory transmission services are provided to all potential retail power competitors.

Further, as stated previously in Section IV.C.1.b (Transmission Providers Taking Service Under Their Tariff), we clarify that a transmission provider does not have to ''take service'' under its own tariff for the transmission of power that is purchased on behalf of bundled retail customers.

Oppose Buy-Sell Transaction Analysis

PA Com asserts that there is a potential for jurisdictional conflict with respect to buy-sell transactions that is a direct consequence of the technical-functional test (which PA Com challenges).

IL Com argues that states have exclusive authority to regulate buy-sell arrangements as bundled retail sales. It further argues that the Commission cannot make a bundled retail sale into an unbundled retail sale simply by characterizing it as the functional equivalent of an unbundled retail sale; by re-characterizing them the Commission is effectively ordering the unbundling of buy-sell arrangements. It asserts that buy-sell arrangements on the electric side are not an end run around clear federal jurisdiction and that the Commission should withdraw its assertion of jurisdiction over the retail transmission component of unbundled retail sales.

VT DPS contends that the Commission's rationale is flawed: ''FERC's analysis rests on the same very shaky ground as its similar claim of jurisdiction over buy-sell arrangements by local gas distribution companies.'' According to VT DPS, all retail transactions are subject to state jurisdiction and asks the Commission to clarify that the Commission defines buy-sell as it did in the NOPR, but also acknowledge that it has no jurisdiction over such arrangements.

IN Com asserts that in the absence of any record of abusive and undermining actions by states under the guise of buy-sell arrangements, there is not even a remedial justification to touch buy-sell transactions. It contends that a difference between the FPA and the NGA warrants different treatment—the FPA exempts from FERC jurisdiction local distribution and transmission of electric energy in intrastate commerce. By redefining interstate transmission, IN Com claims that the Commission proposes to do away with the meaning history has accorded to a variety of transactions previously considered wholly intrastate in nature. According to IN Com, states should be allowed to experiment with and allow different forms of buy-sell transactions as part of the evolving marketplace.

Commission Conclusion

Four parties (PA Com, IL Com, VT DPS and IN Com) have raised concerns regarding the Commission's determination that it has jurisdiction over the interstate transmission component of transactions in which an end user arranges for the purchase of generation from a third party. The Commission reiterates that we will have to address these situations on a case-by-case basis. We disagree with IL Com that States have exclusive authority to regulate the interstate transmission component of buy-sell transactions. Similarly, we deny the VT DPS request that we acknowledge no jurisdiction over such arrangements. The fact remains that these arrangements *could* be used by parties to obfuscate the true transactions taking place and thereby allow parties to circumvent Commission regulation of transmission in interstate commerce. We reserve our authorities to ensure that public utilities and their

[466] *See Colton*, 376 U.S. at 210 n.6; *CL&P*, 324 U.S. at 531–36.

[467] Pacific Gas and Electric Company, *et al.,* 77 FERC ¶ 61,325 at 61,325 (1996).

customers are not able to circumvent non-discriminatory transmission in interstate commerce. In response to VT DPS' contention that the Commission's analysis here rests on the same shaky ground as its similar claim of jurisdiction over buy-sell arrangements by local gas distribution companies, we note that the D.C. Circuit recently affirmed the Commission's assertion of jurisdiction over buy/sell arrangements under the Natural Gas Act.[468]

State Jurisdiction Over the Service of Delivering Electric Energy to End Users

Rehearing Requests

IL Com states that it is far from clear what FERC contemplates by the ''service'' of delivery of electric energy by a delivering utility in the retail wheeling transaction. It is equally unclear to IL Com whether the ''service'' to which Order No. 888 refers is a public utility activity over which state regulators would have jurisdiction. IL Com argues that it is the Illinois legislature, not FERC, that determines whether IL Com can regulate something called ''delivery service.''[469]

MO/KS Coms ask the Commission to clarify the meaning of the statement that even when the test for local distribution facilities identifies no local distribution facilities, the Commission believes that states have authority over the service of delivering electric energy to end users. According to MO/KS Coms:

> The authority to shop at retail and to sell at retail do not exist in the FPA. If the Commission's goal is to recognize the States' authority to establish conditions on retail competition, it need only acknowledge the State jurisdiction to establish the opportunity to shop and sell at retail. If this is what the Commission is seeking to accomplish by its discussion of 'delivery service,' then we support the Commission.[470]

Coalition for Economic Competition asserts that the Commission failed to consider that the sale of electric energy may take place outside of the state into which the energy is transmitted, and that the local regulatory commission may have no jurisdiction over either the sale or the transmission of the energy.

Commission Conclusion

Several parties ask us to clarify our conclusion that even when the seven-factor test for local distribution facilities does not identify local distribution facilities, we believe states have authority over the ''service'' of delivering electric energy to end users. We clarify that states have the authority to determine the retail marketing areas of electric utilities within their jurisdictions, and the end user services that those utilities must provide, but we did not in Order No. 888 intend to opine on the extent of authority given by state legislatures to their state commissions. Rather, our statement regarding state authority over the ''service'' of delivering electric energy is intended to recognize the historical and local nature of delivering power to end users and the states' legitimate concerns and responsibilities in regulating local matters.

Deference to States

Rehearing Requests

Support Broader Deference

NARUC and IL Com argue that the Commission should not simply defer to state recommendations concerning the application of the seven-factor test or the recovery of stranded costs, but should conclusively rely on the findings by state commissions.

NY Com argues that the Commission should not limit deference to instances in which states order retail wheeling, but should defer to all state commission recommendations regarding the definition of local distribution facilities.

FL Com asserts that the Rule fails to say where deference will be given. It argues that the Rule should state that when a state commission has held a proceeding on matters related to the requirements of the Rule, the Commission shall give deference to the state commission decisions. Moreover, it asserts that the Commission should codify the deference standard: ''When a state commission has held a proceeding on matters related to the requirements of this rule, the Commission shall give deference to the state commission decisions.'' (FL Com at 7–9).

The commitment to defer to a state regulatory commission or agency, argues NE Public Power District, should be clarified with respect to utilities located in Nebraska, which has no such commission or agency. NE Public Power District assumes that deference will be accorded to decisions of NE Public Power District's Board of Directors; if not, it asks the Commission to clarify.

PA Com asks the Commission to clarify what a state regulatory agency must demonstrate to secure deference and to define the term ''consult.'' PA Com states that, in discussing the seven indicia, the Commission states that it will ''consider'' jurisdictional recommendations by states, which PA Com asserts is much different from deference. It also asserts that the Commission must clarify what it will do if a utility's classifications and/or cost allocations are not supported by state regulatory authorities.

Oppose Deference to State Authorities

TANC argues that the Commission erred in deferring to state regulatory authorities in drawing jurisdictional lines for local distribution facility classifications and/or cost allocations. According to TANC, the Commission unlawfully and unnecessarily abdicated its jurisdiction under the FPA (citing *New England Power Co.* v. *New Hampshire*, 455 U.S. 331, and *Nantahala Power and Light Co.* v. *Thornburg*, 476 U.S. 953). With respect to ISOs, it asserts that the Commission should not defer to state authority in making determinations with respect to classifications of facilities.

Commission Conclusion

In response to NARUC and IL Com's arguments that this Commission should not simply defer to state commissions regarding application of the seven-factor test but instead should conclusively rely on the findings of state commissions, we believe this is inconsistent with the case law which states that local distribution it is a matter of fact for the Commission to determine as an original matter.[471] Additionally, we have an independent obligation to ensure that we are fulfilling our responsibilities under the FPA to regulate facilities that are used in interstate commerce. We cannot delegate our jurisdiction. However, we intend to provide broad deference to states in determining what facilities are Commission-jurisdictional transmission facilities and what facilities are state-jurisdictional local distribution facilities, so long as our comparability principles are not compromised and we are able to fulfill our responsibilities under the statute.

We reject FL Com's suggestion that we codify the deference standard. This is neither necessary nor appropriate. In response to NE Public Power District's request that we clarify to whom we would give deference in Nebraska, we clarify that because Nebraska does not have an electric regulatory commission or agency, there is no appropriate regulatory entity to whom our deference standard would apply; accordingly, we will address the transmission/local

[468] *United Distribution Companies*, 88 F.3d at 1154–57.

[469] *See also* AK Com (should not create a fictional concept of delivery service—the legal reality is that, under retail competition, state law will establish a customer's right to be served and a generation owner's right to produce power. AK Com asserts that the state can then attach conditions to those rights).

[470] MO/KS Coms at 1–13.

[471] *See Colton* and *Connecticut Light and Power, supra.*

distribution issue for Nebraska without giving deference to any particular entity. In response to PA Com's request that we clarify what we will do if a utility's classifications and/or cost allocation proposals are not supported by state regulatory authorities, we will make a determination based on the factual record before us in a particular case, taking into account the views of the state regulatory authority.

TANC has argued that we have unlawfully abdicated our jurisdiction by deferring to state recommendations. TANC confuses delegation of jurisdiction, which we cannot do, with willingness to defer to states based on their application of criteria that we have provided. Even in the cases in which the Commission defers to states' views, we will still independently evaluate all material issues and proceed only where substantial evidence supports the states' views. The Commission clearly can entertain requests for deference in these circumstances.

J. Stranded Costs

As indicated in our prior discussion in Section IV.A.5, there are two major overlapping transition issues that arise as a result of this rulemaking: stranded cost recovery and how to deal with contracts entered into under the prior regulatory regime. We here address stranded cost recovery and, as in the prior discussion, we believe it is important to explain the general context in which our stranded cost determinations have been made before addressing the various rehearing requests on this issue.

In Order No. 888, the Commission removed the single largest barrier to the development of competitive wholesale power markets by requiring non-discriminatory open access transmission as a remedy for undue discrimination. This action carries with it the regulatory public interest responsibility to address the difficult transition issues that arise in moving from a monopoly, cost-based electric utility industry to an industry that is driven by competition among wholesale power suppliers and increasing reliance on market-based generation rates. The most critical transition issue that arises as a result of the Commission's actions in this rulemaking is how to deal with the uneconomic sunk costs that utilities prudently incurred under an industry regime that rested on a regulatory framework and a set of expectations that are being fundamentally altered.

The Commission determined in Order No. 888 that it must address stranded costs, and that it must do so at an early stage—particularly in light of the lessons learned from our experience with similar issues in the natural gas area. We noted that when we did a similar restructuring in the gas industry, the D.C. Circuit invalidated the Commission's efforts precisely because the Commission had failed to deal with the stranded cost problem in a satisfactory manner.[472] We explained that, based on the lesson of *AGD*, the Commission cannot change the rules of the game without providing a mechanism for recovery of the costs caused by such regulatory-mandated change.

Since the time Order No. 888 issued, we have been provided with additional guidance from the court in the natural gas area, which has further helped to inform our decisions here. In its decision on review of Order No. 636,[473] the D.C. Circuit upheld the Commission's decision to allow the recovery of gas supply realignment costs. In so doing, the court, while questioning a specific feature of the stranded cost recovery mechanism employed in Order No. 636, has nevertheless again reaffirmed the basic principle that stranded cost recovery is an appropriate component of a regulatory policy aimed at accomplishing a fair and reasonable transition to competitive markets. The question as to the Commission's ability to allow the recovery of stranded costs has been laid to rest.

The task before the Commission in this rulemaking is thus to determine how best to meet its responsibility to address the costs of the transition to a competitive industry, particularly insofar as those costs are stranded, or in effect rendered unrecoverable, as a result of the transmission access required by us under the FPA.[474] As the rehearing arguments demonstrate, there is no consensus on how the Commission should address the stranded cost issue. In fact, petitioners are at polar extremes as to what the Commission should do regarding stranded costs. Some argue that the Commission has gone too far in permitting utilities to seek recovery of stranded costs, whether such costs are associated with wholesale requirements contracts, with retail-turned-wholesale customers, or with retail customers that obtain retail wheeling.[475] Others argue that the Commission has not gone far enough and that it must broaden the scope of stranded cost recovery permitted under the Rule. Indeed, some would have us be the guarantor for recovery of all uneconomic costs that might be stranded in the move to more competitive markets, no matter how tenuous the nexus to this Rule, and irrespective of state-Federal jurisdictional complexities. Some support the Commission's decision to recover stranded costs directly from the departing customers. Others would prefer that the Commission require utilities to absorb a portion of their stranded costs or that the Commission spread the burden of stranded costs among all of the utility's customers. Some object that the Commission's approach to stranded costs in the electric industry is different from that adopted in the gas industry. Some entities support the Commission's revenues lost approach for measuring a departing customer's stranded cost obligation. Others propose different methods for computing stranded costs.

Given the plethora of positions that entities have raised both initially and on rehearing concerning stranded costs, the Commission has taken a careful, measured approach with regard to stranded cost recovery. The Commission has balanced a number of important interests in order to achieve what it believes will be a fair and orderly transition to competitive markets. These interests include the financial stability of the electric utility industry, upholding the regulatory bargain under which utilities made major capital investments, and not shifting costs to customers that had no responsibility for causing those costs to be incurred. The Commission also has adopted an approach that, for purposes of stranded cost recovery from wholesale transmission customers, relies on the nexus between stranded costs and the use of transmission tariffs required by this Commission and, for purposes of stranded cost recovery from retail customers, recognizes state commission

[472] Associated Gas Distributors v. FERC, 824 F.2d 981 (D.C. Cir. 1987), *cert. denied*, 485 U.S. 1006 (1988) (*AGD*).

[473] United Distribution Companies v. FERC, 88 F.3d 1105 (1996) (*United Distribution Companies*).

[474] Such access may be the open access required under this Rule or case-by-case transmission access ordered pursuant to FPA section 211.

[475] We note that the regulations implementing this Rule use ''wholesale stranded cost'' and ''retail stranded cost'' as shorthand terms to refer to the different situations in which a utility may experience stranded costs. However, as the definitions of those terms make clear, it is *not* the nature of the *costs* (wholesale vs. retail) that is controlling for purposes of stranded cost recovery under this Rule. Rather, the controlling factors are the status of the *customer* (wholesale transmission services customer vs. retail transmission services customer) with whom the costs are associated, and whether the transmission tariffs used by the customer to escape its former power supplier (thus causing the stranding of costs to occur) were required by this Commission or by a state commission. As a result, ''retail stranded costs'' refers to stranded costs associated with retail wheeling customers.

jurisdiction but fills potential regulatory gaps that could arise in the transition to new market structures.

The balancing of interests and considerations described above is reflected in the following central components of the Rule's stranded cost provisions, which are reaffirmed herein.[476] First, the Commission has determined that the most reasonable, legally supportable approach is one that permits utilities to seek recovery of wholesale stranded costs under this Rule (whether the stranded costs are associated with a departing wholesale requirements customer or with a retail-turned-wholesale customer) only in those cases in which there is a *direct nexus* between the availability and use of Commission-required transmission access[477] and the stranding of costs. In order for the utility to be eligible to seek recovery of stranded costs from a departing customer, the customer must have obtained access to a new generation supplier through the use of the former supplying utility's Commission-required transmission tariff (*i.e.*, its open access tariff or a tariff ordered pursuant to FPA section 211), not through the use of another utility's transmission system.

Other cost recovery issues are more appropriately addressed outside the context of this Rule. For example, the Rule is *not* intended to apply to costs associated with the normal risks of competition, such as self-generation, cogeneration, or loss of load, that do not arise from the new, accelerated availability of Commission-required transmission access. If a customer leaves its utility supplier by exercising options that could have been undertaken prior to mandatory transmission under Order No. 888 or the Energy Policy Act, or that do not rely on access to the former seller's transmission, there is no direct nexus to Commission-required transmission access and thus no opportunity for stranded cost recovery under the Rule.

Second, the Commission has limited the opportunity to seek stranded cost recovery under the Rule primarily to two discrete situations: (1) Costs associated with customers under wholesale requirements contracts executed on or before July 11, 1994 (referred to in the Rule as ''existing wholesale requirements contracts'') that do not contain an exit fee or other explicit stranded cost provision; and (2) costs associated with retail-turned-wholesale customers. With regard to the existing wholesale requirements contracts, the Commission also has made a finding that it is in the public interest to permit amendments to add stranded cost provisions to these contracts, even if they contain *Mobile-Sierra* clauses, if case-by-case evidentiary burdens are met. We do not interpret the *Mobile-Sierra* public interest standard as practically insurmountable in extraordinary situations such as this one where historic statutory and regulatory changes have converged to fundamentally change the obligations of utilities and the markets in which they and their customers will operate.

Third, Order No. 888 *does not guarantee* that a utility will be allowed to recover stranded costs. Rather, it provides an *opportunity* for such recovery. To be eligible to recover stranded costs from a departing customer in a particular case, the utility must demonstrate that it incurred costs to provide service to the customer based on a reasonable expectation of continuing service to that customer beyond the contract term.[478] In the case of stranded costs associated with wholesale requirements contracts customers, if the contract contains a notice of termination provision, that provision is strong evidence that the parties were aware that at some point in the future the customer might seek to find another supplier. Therefore, there is a rebuttable presumption of no reasonable expectation, and therefore no opportunity for stranded cost recovery unless the utility can overcome the presumption.

The Commission has concluded that direct assignment of stranded costs to the departing customer (through either an exit fee or a surcharge on transmission) is the appropriate method for recovery of stranded costs under the Rule. In reaching this conclusion, the Commission carefully weighed the arguments supporting direct assignment of stranded costs against those supporting a more broad-based approach, such as spreading stranded costs to all transmission users of a utility's system, and also took into account the fact that we applied a different approach in the natural gas area. The central considerations that support a direct assignment approach in the electric industry are that the approach follows the traditional regulatory concept of cost causation, it avoids shifting costs to customers that had no responsibility for causing them to be incurred or for causing them to be stranded, and it is still possible to apply such an approach at this stage of the industry's evolution.

There is no question that, without the stranded cost recovery mechanism, some customers would be far more likely to switch to lower-cost suppliers and enjoy sooner the benefits of a competitive power market. But, as detailed in Order No. 888, such an approach may result in higher costs for other customers. We thus have had to balance the potential for earlier benefits for some customers against other public interest considerations, most particularly the need to provide a fair mechanism by which utilities can recover the costs of past investments under traditional regulatory concepts of prudently incurred costs and cost causation. The result is not to deny competitive advantages, but only to delay their full realization for some customers so that all customers ultimately will benefit.

While Order No. 888's cost causation approach is different from the Order No. 636 cost spreading approach that was affirmed in the *United Distribution Companies* case, we believe it is the preferable approach given the early stage of the electric utility's competitive transition. We do not read the court's opinion as precluding the Commission from adopting a direct assignment approach in Order No. 888, particularly where, as here, the Commission has fully explained and justified the reasons for following traditional cost causation principles. In addition, although the *United Distribution Companies* court remanded for further consideration (in light of Order No. 636's cost spreading approach) the decision not to require any pipeline absorption of gas supply realignment costs, the Commission has fully explained how its decision in Order No. 888 not to require any utility absorption of stranded costs is consistent with its decision to follow traditional cost causation principles. With respect to the fundamental conclusion that utilities should be permitted an opportunity to recover their prudently incurred costs, Order No. 888 is fully consistent with Order No. 636. Although the Commission in Order No. 888 chose a direct assignment method (rather than the cost-spreading

[476] We reaffirm below our basic determinations, but make certain clarifications on limited issues and grant rehearing on the municipal annexation issue.

[477] As we explain below, by ''Commission-required transmission access'' we mean the open access transmission required under this Rule or required pursuant to a section 211 order, as well as transmission provided prior to Order No. 888 (and not pursuant to a section 211 order) where such transmission was provided on a case-by-case basis to comply with the Commission's comparability requirement. *See* note 484 *infra*.

[478] We have made a minor revision to the regulatory text, section 35.26(c)(2), to conform the language of that section with sections 35.26(b) (1) and (5). A conforming revision has been made to section 35.26(d)(2)(i).

approach in Order No. 636) for purposes of allocating stranded cost responsibility among customers, the approach used by the Commission in Order No. 888 is not governed by decisions in Order No. 636, but in either event the Commission must demonstrate that its choice of methods is based on reasoned decision-making.

In considering the stranded cost issues that may arise in the transition to competitive markets, the Commission also has taken cognizance of significant changes involving retail customers and the stranded cost issues that arise as retail customers convert to wholesale customer status (*e.g.,* through municipalizations) in order to obtain the open access afforded by Order No. 888, or as they obtain retail wheeling required by state commissions. These situations involve new and complex jurisdictional issues and represent the bulk of potential stranded costs facing the industry. We believe it is important to clarify the Commission's decisions as to when it will entertain requests for stranded cost recovery in these situations, and our reasons for doing so.

The Commission's determination that it, rather than the states, should be the primary forum for addressing stranded costs associated with a retail-turned-wholesale customer [479] is limited to those cases in which there is a *direct nexus* between the availability and use of Commission-required transmission access and the stranding of costs. We believe we have both the authority and the obligation to provide an opportunity for stranded cost recovery in these situations because the bundled retail customer would not be able to obtain access to the new supplier *but for* the Commission's order requiring transmission. The creation of a new wholesale entity to purchase power on behalf of retail customers would not, by itself, trigger stranded costs. In the absence of transmission access from the historical supplier of the retail customers, the new entity would have to remain on the historical supplier's generation system because it would have no way to reach other power suppliers, and stranded costs would not occur.[480] Therefore, there is a causal nexus between the stranded costs and the availability and use of the tariff services *required by the Commission.*[481] Moreover, because of this causal nexus between the use of a jurisdictional utility's Commission-required transmission tariff and the potential for foregone revenues by that jurisdictional utility as a result of the Commission-required access, the stranded costs associated with a retail-turned-wholesale customer are properly viewed as economic costs that are jurisdictional to this Commission.

In contrast, in the situation in which a bundled retail customer obtains retail wheeling, stranded costs are directly caused by the availability and use of unbundled retail services *required by the state commission,* not this Commission.[482] Thus, the Commission believes that states, not the Commission, should be the primary forum for costs associated with a bundled retail customer that obtains retail wheeling. The Commission's decision to entertain requests to recover stranded costs caused by retail wheeling in *only* a limited circumstance (where the state regulatory authority does not have authority under state law to address stranded costs when the retail wheeling is required) is based on a policy decision by this Commission that it will step in to fill a regulatory ''gap'' that could result in no effective forum in which utilities would have an opportunity to seek recovery of prudently incurred costs.

Finally, after considering various proposals regarding how stranded costs should be calculated, and reviewing the arguments of petitioners on rehearing, the Commission continues to believe that the revenues lost approach is the fairest and most efficient way to determine the amount of stranded cost assigned to a departing customer during the transition to a competitive wholesale bulk power market. The Commission has rejected an asset-by-asset approach as overly complicated and costly.

We respond below to the specific arguments raised on rehearing and elaborate on the above determinations.

1. Justification for Allowing Recovery of Stranded Costs

In Order No. 888, the Commission concluded that utilities should be given the opportunity to seek recovery of legitimate, prudent and verifiable stranded costs associated with a limited set of wholesale requirements contracts executed on or before July 11, 1994.[483] We stated that utilities that entered into contracts to make wholesale requirements sales under an entirely different regulatory regime should have an opportunity to recover stranded costs that occur as a result of customers leaving the utilities' generation systems through Commission-jurisdictional open access tariffs or FPA section 211 orders to reach other power suppliers. We explained that utilities that made large capital expenditures or long-term contractual commitments to buy power years ago to supply their customers should not now be held responsible for failing to foresee the actions this Commission would take to alter the use of their transmission systems in response to the fundamental changes that are taking place in the industry. We found that recent significant statutory and regulatory changes are central to the circumstances that now place at risk the recovery of past investment decisions of utilities. We indicated that we will not ignore the effects of these changes as we fashion policies that will govern possible recovery of these costs in the transition to an open access regulatory regime.

We stated that while there has always been some risk that a utility would lose a particular customer, in the past that risk was smaller. It was not

[479] In Order No. 888 and here, we sometimes use the shorthand expression ''retail-turned-wholesale'' customer. By this we do not mean that a retail customer who is an ultimate consumer ceases to be an ultimate consumer, or that this customer begins to purchase electric energy for resale. Rather, in a ''retail-turned-wholesale customer'' situation, such as the creation of a municipal utility system, a newly-created entity becomes a wholesale power purchaser on behalf of retail customers who were formerly bundled customers of the historical local utility power supplier. The new municipal utility is the conduit by which retail customers, if they cannot obtain direct retail access, can reach power suppliers other than their historical local utility power supplier. Although the retail customers remain bundled retail customers, in that they become the bundled customers of the new entity, we call this a ''retail-turned-wholesale customer'' situation because the new entity in effect ''stands in the shoes'' of the retail customers for purposes of obtaining wholesale transmission access and new power supply.

[480] Exceptions would be self-generation or construction by the new entity of its own transmission line, in which case, as noted earlier, the stranded cost provisions of Order No. 888 would not apply because such options have always been available as alternatives to purchasing power from the historical supplying utility and do not involve the use of the utility's transmission facilities under an open access tariff. Thus the departure of customers under these circumstances cannot be linked to the open access requirements of this Rule.

[481] As discussed in greater detail in Sections IV.J.6 and IV.J.12 below, we clarify that the opportunity for recovery of stranded costs in a retail-turned-wholesale situation is limited to cases in which the former bundled retail customer subsequently becomes, either directly or through another wholesale transmission purchaser, an unbundled wholesale transmission services customer of its former supplier. We have revised section 35.26(b)(1)(i) of the Commission's regulations accordingly.

[482] Unbundled retail transmission services required by a state commission could be taken under the same pro forma open access tariff used by wholesale customers or, if determined appropriate by the Commission, under a separate retail tariff filed at the Commission. The critical point, however, is that in either case, the unbundled services are required by the state and not by this Commission.

[483] FERC Stats. & Regs. at 31,788–91; *mimeo* at 451–58.

unreasonable for the utility to plan to continue serving the needs of its wholesale requirements customers and retail customers, and for those customers to expect the utility to plan to meet their future needs. We concluded that with the new open access transmission, [484] the risk of losing a customer is radically increased. If a former wholesale requirements customer or a former retail customer uses the new open access to reach a new supplier, the utility is entitled to seek recovery of legitimate, prudent and verifiable costs that it incurred under the prior regulatory regime to serve that customer. The utility, however, would have the burden of demonstrating that it had a reasonable expectation of continuing to serve the departing customer.

Rehearing Requests Opposing, or Seeking Limitations on, Stranded Cost Recovery

Several entities challenge the Commission's decision to give utilities an opportunity to recover legitimate, prudent and verifiable stranded costs. NASUCA argues that the transition to wholesale competition was underway before and apart from the NOPR. It asserts that the drivers of the developing competition include voluntary open access filings by utilities seeking mergers or market-based rate authority and section 211 of the FPA, as amended by the Energy Policy Act of 1992 (Energy Policy Act). According to NASUCA, stranded investment results from legislative, not regulatory action, and the stranded cost issue does, and would, exist without the Open Access Rule. It contends that an acceleration of the competitive wholesale transformation does not change its nature or origins. NASUCA also contends that the issuance of the Open Access Rule does not justify stranded cost recovery on ''regulatory compact'' grounds because it is not a fundamental change.

Other entities object that there is no basis for the Commission to impute an extra-contractual obligation to serve wholesale requirements customers.[485] These entities argue, for example, that utilities could and should have protected themselves from any potential stranded costs through individual customer contracts.

IN Consumer Counselor and IN Consumers object that Order No. 888 attempts to transform the obligation to provide a utility with an ''opportunity'' for a fair return when prices are regulated into an ''entitlement'' to ''recover legitimate, prudent and verifiable costs that it incurred under the prior regulatory regime.'' [486]

Several entities submit that the Commission has not adequately addressed the potential anticompetitive impact of stranded cost recovery.[487] Some argue that giving utilities the opportunity to recover wholesale stranded costs will delay the opportunity for historically captive customers to benefit from competitive alternatives.[488] Central Illinois Light contends that the Rule is arbitrary and capricious because it will have different impacts on different customers, which Central Illinois Light asserts will be due to accidents of circumstance rather than the conscious application of rational policy choices. IN Consumers objects that two similarly-situated customers of the utility for identical transmission services will be required to pay substantially different rates for the same service (where one previously purchased its power requirements from the utility, while the other used an alternate source of supply).

Central Illinois Light also objects that even a partial allowance of stranded costs will likely encourage predatory pricing. It says that the Commission has failed to adequately address the harm that stranded cost ''subsidies'' pose to low-cost utilities with little or no stranded costs. Others contend that the Rule would subvert economic efficiency by unjustly enriching utilities that have not attempted to meet the new market demands, to the detriment of those utilities that have.[489] According to Occidental Chemical, the Commission has made no finding that the pro-competitive goals of Order No. 888 can be accomplished in light of the costs and uncertainties presented by stranded cost recovery.

Several entities also challenge the adequacy of the factual record for allowing wholesale stranded cost recovery and argue that utilities have not provided the hard data on wholesale stranded costs that the Commission needs to justify Order No. 888.[490] Central Illinois Light objects that the Commission failed to note or to discuss data presented by commenters showing that only a small group of high-cost utilities need some stranded cost protection. American Forest & Paper argues that the Commission has failed to demonstrate on the record the existence of any stranded wholesale investment that was or could be caused by the transition to open access transmission.

SC Public Service Authority repeats its earlier request that the Commission deny market-based rate authority to any utility that elects to recover stranded costs from departing customers.[491] It objects that the Commission failed to specifically respond to its previous comments on this issue.

American Forest & Paper objects that utilities that voluntarily filed open access tariffs cannot use the stranded cost rule because their loss of customers cannot be said to have occurred only because of the Rule. It submits that only those utilities who had to be forced to offer open access transmission are being rewarded.

San Francisco asks that the Commission include ''exercise of pre-existing contract rights for transmission and designation of wholesale loads'' or similar language as one of the examples (listed in footnote 718) of situations for which stranded costs may not be sought. San Francisco explains that it wants to ensure that PG&E would not have any basis to argue that any load loss PG&E suffers as a result of San Francisco's designation of municipal loads would be eligible for stranded cost recovery.

Commission Conclusion

We will deny the requests for rehearing of our decision to allow

[484] In Order No. 888, we explained that by ''new open access'' or ''open access transmission'' we were referring to Commission-jurisdictional open access tariffs or to a tariff ordered pursuant to FPA section 211. Although we generally refer in the text of Order No. 888 and the text of this order to the open access tariffs required under this Rule and to tariffs required pursuant to a section 211 order, we clarify that the ''new open access'' or ''open access transmission'' described in this Rule also includes transmission provided prior to Order No. 888 (and not pursuant to a section 211 order) where such tariff filings were made on a case-by-case basis to comply with the Commission's comparability requirement. To avoid any confusion on this point, we refer in this order to all such open access transmission as ''Commission-mandated transmission access'' or ''Commission-required transmission access.''

[485] *E.g.*, American Forest & Paper, Blue Ridge, TDU Systems, IN Consumer Counselor, IN Consumers, IL Com.

[486] IN Consumer Counselor at 9 (citing Order No. 888, *mimeo* at 452–53); IN Consumers at 10 (same).

[487] *E.g.*, APPA, IN Consumer Counselor, IN Consumers, Suffolk County, TDU Systems, Specialty Steel, Occidental Chemical, Central Illinois Light, American Forest & Paper, Nucor, Blue Ridge.

[488] *E.g.*, APPA, IN Consumer Counselor, IN Consumers, Suffolk County, TDU Systems, Specialty Steel.

[489] *E.g.*, American Forest & Paper, Nucor, Blue Ridge.

[490] *E.g.*, ELCON, TDU Systems, Central Illinois Light, American Forest & Paper.

[491] *See also* American Forest & Paper (unless a utility agrees not to seek stranded costs under the Rule, the utility should not be found to have mitigated its transmission market power for purposes of charging market-based rates, merging with other utilities or otherwise, simply by filing an open access tariff).

utilities an *opportunity* to seek recovery of legitimate, prudent, and verifiable stranded costs. As we indicated in Order No. 888, we learned from our experience with natural gas that, as both a legal and a policy matter, we cannot ignore these costs. The U.S. Court of Appeals for the District of Columbia Circuit invalidated the Commission's first open access rule for gas pipelines because the Commission failed to deal with the uneconomic take-or-pay situation that many pipelines faced as a result of regulatory changes beyond their control.[492] That same court has subsequently affirmed the Commission's decision to allow the recovery of costs that are stranded in the transition to a competitive natural gas industry, most recently by upholding the Commission's decision in Order No. 636 to allow the recovery of gas supply realignment costs.[493]

Here we are faced, once again, with an industry transition in which there is the possibility that, as a result of statutory and regulatory changes beyond their control, certain utilities may be left with large unrecoverable, legitimate and prudent costs or that those costs will be unfairly shifted to other (remaining) customers. Thus, in order to satisfy our regulatory responsibilities, we must directly and timely address the costs of the transition by allowing utilities to seek recovery of legitimate, prudent and verifiable stranded costs.[494] While the transition to wholesale competition may have begun before the NOPR, we strongly disagree with NASUCA's claim that the Open Access Rule does not justify stranded cost recovery because an acceleration of the transition does not change its nature or origins. The driving force behind the development of wholesale competitive markets is the widespread transmission access made available through Commission-mandated transmission tariffs,[495] including transmission tariffs ordered pursuant to FPA section 211 and the transmission tariffs required by the Commission's Open Access Rule.[496] Furthermore, as explained in the Rule and as further discussed below, it is the ability of customers to obtain readily available Commission-mandated transmission access that significantly increases the potential for wholesale stranded costs.

Order No. 888 requires the functional unbundling of a public utility's wholesale services. Under the Rule, all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce were required by July 9, 1996 to file open access transmission tariffs that contain minimum terms and conditions of non-discriminatory service (or to seek waiver), and to take transmission service (including ancillary services) for their own new wholesale sales and purchases of electric energy under the open access tariffs. As a result of Order No. 888, wholesale requirements customers that previously were captive customers of their public utility suppliers (*i.e.*, they had no choice but to take bundled sales and transmission services from their suppliers) will be able at the expiration of their contracts to take unbundled transmission service (*i.e.*, transmission-only service) from their former suppliers in order to reach new suppliers. While in the past there has been some risk of stranded costs due to customers ''leaving'' a supplier's system through self-generation or perhaps municipalization, there was little or no ability to shop for alternative power such as that which will occur as a result of readily available Commission-mandated transmission access. Contrary to NASUCA's claims, Order No. 888, coupled with section 211 of the FPA, creates the opportunity, as a matter of law, for an existing wholesale requirements customer to use the transmission owner's facilities to reach a new supplier.[497] This leaves the former supplying utility with significant risk that it will be unable to recover costs that the utility incurred based on a reasonable expectation that it would continue to serve the departing customer.

Thus, the regulatory and statutory changes contained in Order No. 888 and in amended section 211, which will act in tandem to provide the transmission access necessary to develop the competitive wholesale markets envisioned by Congress in the Energy Policy Act, have a direct nexus to the potential for wholesale stranded costs. This nexus makes it critical that the Commission address this transition issue responsibly and equitably. Having balanced the goals of competition, the nexus between potential stranded costs and transmission access, and the regulatory bargain under which utilities invested billions of dollars in reliance on the prior regulatory regime, we believe that utilities are entitled to an opportunity to seek recovery of stranded costs and that our actions in Order No. 888 are not only legally supportable, but also represent sound public policy.

In response to those entities who argue that there is no basis for imputing an extra-contractual obligation to serve wholesale requirements customers, as we explained in Order No. 888, we believe there previously has been an implicit obligation to serve at wholesale in many cases. Such obligation is based, in large part, on the recognition that historically most wholesale requirements customers were captive and had no means of reaching alternative suppliers. The local utility supplied bundled generation and transmission services to these customers on the assumption that they would remain as customers. Accordingly, the utility had a concomitant obligation to plan to supply these customers'

[492] *AGD*, 824 F.2d at 1021.

[493] *United Distribution Companies,* 88 F.3d 1105 (1996). Although the court remanded that aspect of Order No. 636 that allows pipelines to recover 100 percent of their gas supply realignment costs without requiring any pipeline absorption, we explain in Section IV.J.3 below how Order No. 888 is fully consistent with that remand.

[494] *See* FERC Stats. & Regs. at 31,789; *mimeo* at 453–54.

[495] As we explain above, Commission-mandated transmission tariffs is meant to include all open access tariffs filed pursuant to Commission order, including tariffs filed under this Rule, tariffs ordered pursuant to FPA section 211, and tariffs that were filed on a case-by-case basis to comply with the Commission's comparability requirement.

[496] As a result of the Open Access Rule, 47 Group 2 public utilities, which had no open access transmission tariff available prior to Order No. 888, submitted and had available on July 9, 1996 non-discriminatory open access transmission tariffs. In addition, 101 Group 1 public utilities, which had some version of open access available prior to Order No. 888, filed new open access tariffs effective July 9, 1996 in order to conform to the terms and conditions of non-discriminatory open access service specified in the pro forma tariff. Thus, as of July 9, 1996, 148 of the 166 public utilities had filed Order No. 888 open access tariffs. At least ten others filed open access tariffs after July 9, 1996 (*e.g.*, after the Commission dealt with their waiver requests). This, in the Commission's view, represents an unprecedented acceleration of the transition to competitive bulk power markets. From the issuance of the Open Access NOPR in March 1995 until the effective date of Order No. 888 on July 9, 1996 is only a little more than one year.

[497] NASUCA and other petitioners offer no persuasive evidence that meaningful competition took root prior to the availability of the new transmission access requirements. The few utilities that did provide transmission service under open access tariffs prior to the announcement of the Commission's comparability requirement did not offer third parties comparable service. To the contrary, such tariffs contained numerous disparities in the transmission service that the utilities provided to third parties in comparison to their own uses of the transmission system. *See, e.g.*, Entergy Services, Inc., 58 FERC ¶ 61,234, *order on reh'g*, 60 FERC ¶ 61,168 (1992), *remanded, sub nom.*, Cajun Electric Power Cooperative, Inc. v. FERC, 28 F.3d 173, 179–80 (D.C. Cir. 1994) (tariff contained limitations on point-to-point service and did not provide network service; tariff reserved transmission provider's right to cancel service in certain instances, even where a customer had paid for transmission system modifications). While the desire of customers for competitive power markets may have preceded Commission-mandated open access, customers had no assurance they could reach alternative suppliers until the Commission required utilities to provide transmission service on a comparable basis.

continuing needs, and planned its system taking account of the wholesale load. In many cases the wholesale customers participated by supplying load forecasts. Consistent with this practical obligation to serve, the Commission viewed the supplying utility as the supplier of first resort, and did not allow a utility to terminate service without prior Commission approval. Before Order No. 888, the Commission's regulations required prior notification and approval of the proposed cancellation or termination of a wholesale requirements contract. We note that although Order No. 888 eliminates the prior notice of cancellation or termination requirement for power sales contracts executed on or after July 9, 1996 (the effective date of the Open Access Rule) that are to terminate by their own terms,[498] it expressly retains the prior notice of cancellation or termination requirement for any power sales contract executed before that date.

It is important to note, however, that while the stranded cost recovery provisions of the Rule are based on the implicit obligation to serve, the Rule does not *guarantee* any extra-contractual wholesale stranded cost recovery, much less across-the-board recovery of such costs by all public utilities. To the contrary, it provides an *opportunity* for such recovery only for a discrete set of requirements contracts (those executed on or before July 11, 1994 that do not contain an exit fee or other explicit stranded cost provision), and the Rule requires that a utility must meet a heavy burden of proving eligibility to recover costs in a particular case: before a departing customer is required to pay a stranded cost exit fee or transmission surcharge, the utility must demonstrate that it incurred costs to provide service to a customer based on a reasonable expectation of continuing service to that customer beyond the end of the contract.[499]

We believe that we adequately address in both Order No. 888 and in Section IV.J.2 below the concerns various entities have expressed as to the potential anticompetitive impact of stranded cost recovery. Although we recognize that stranded cost recovery may delay some of the benefits of competitive bulk power markets for some customers, we believe that customers as a whole will benefit from a fair and orderly transition. Indeed, we are particularly concerned that the failure to assign stranded cost responsibilities to customers that have access to alternative suppliers will leave captive customers exposed to the risk of greater cost burdens, thereby shifting to captive customers the costs that were originally incurred for the benefit of the (typically larger) customers who have the flexibility to take early advantage of competing power suppliers. Avoiding this potential cost shifting problem is an important goal of our decision to address the stranded cost problem as part and parcel of the decision to mandate open access. As we said in Order No. 888:

> such transition costs must nevertheless be addressed at an early stage if we are to fulfill our regulatory responsibilities in moving to competitive markets. The stranded cost recovery mechanism that we direct here is a necessary step to achieve pro-competitive results. In the long term, the Commission's Rule will result in more competitive prices and lower rates for consumers.[500]

We do not believe that allowing utilities an opportunity to seek stranded cost recovery will prevent us from achieving the pro-competitive goals of Order No. 888. To the contrary, as discussed below in Section IV.J.3, we think that it is necessary to provide utilities the opportunity to seek to recover stranded costs if we are to have a fair and orderly transition to more competitive bulk power markets. The opponents of Order No. 888's stranded cost approach argue that the transition to fully competitive bulk power markets will be slower if we allow utilities an opportunity to seek to recover stranded costs from departing customers, and with respect to some customers that may well be true. As noted earlier, some customers because of their size and limited contractual obligations with their current utility suppliers have the ability immediately to leave the system. If they are allowed to do so without paying the costs incurred to provide them expected future service, the economic attractiveness of departing the system is obviously enhanced and the benefits of competition, for these customers, obviously come sooner rather than later. However, the pace at which fully competitive markets are achieved, while important, is not the only consideration. It is the Commission's responsibility to ensure that the costs of open access are fairly assigned and that the benefits of Order No. 888's open access requirements will be fairly available to all customers. These dual goals compel us toward a balanced approach that, although perhaps delaying somewhat the benefits of competition, nevertheless ensures that all customers will share in those benefits without undermining historic principles of cost recovery upon which utilities were entitled to rely in planning their systems.

Moreover, as we explain in Section IV.J.3 below, we have carefully examined different methods of allocating stranded costs that are found to be properly recoverable, including assigning the costs directly to the departing customer or spreading the costs to all transmission users of a utility's system. We recognize that the direct assignment approach to stranded cost recovery delays competition for some customers because it attaches a price tag for customers who have the immediate ability to leave the system. However, we have identified the advantages and disadvantages of each approach and have concluded, on balance, that direct assignment is the preferable approach for both legal and policy reasons.

In response to the concerns of some entities that stranded cost ''subsidies'' may harm low-cost utilities with little or no stranded costs, or otherwise may unjustly enrich utilities that have not attempted to meet the new market demands to the detriment of those that have, we again emphasize the limited and transitional nature of the stranded cost recovery opportunity allowed under Order No. 888.[501] It is clearly not the Commission's intent that utilities with little or no stranded cost exposure be competitively disadvantaged by the Open Access Rule. Those utilities with little or no stranded costs will be similarly situated with other new suppliers in the sense that they will all

[498] The Rule requires that the utility notify the Commission of the date of termination for this class of contracts within 30 days after the termination takes place. The Rule retains the prior notice of cancellation or termination requirement for power sales contracts executed on or after July 9, 1996 if termination is on grounds other than expiration of the contract by its terms at the end of the contract. *See* Portland General Electric Company, 75 FERC ¶ 61,310, *reh'g denied* 77 FERC ¶ 61,171 (1996) (Commission authorization required for termination of power sales contract in the event of the commencement of a bankruptcy proceeding, failure to perform any obligation under the contract, or failure to provide adequate assurance of the ability to perform).

[499] To the extent there is any misunderstanding, we clarify that the intent of the Rule to permit the ''opportunity'' to recover stranded costs is not an ''entitlement'' to recover such costs. As a result, the passage in Order No. 888 to which IN Consumer Counselor and IN Consumers object (FERC Stats. & Regs. at 31,789, *mimeo* at 452–53) should read ''we believe that the utility is entitled to *an opportunity to* recover legitimate, prudent and verifiable costs that it incurred under the prior regulatory regime to serve that customer'' (emphasis to show added language).

[500] FERC Stats. & Regs. at 31,794; *mimeo* at 468–69.

[501] As we indicate in Section IV.J.9 below, we disagree that the Rule's definition of stranded costs artificially and unjustifiably improves the competitive position of an inefficient utility.

face the potential of not being able to compete immediately for certain wholesale customers who are determined to have an obligation to pay stranded costs. These customers may find it to be uneconomic to shop from new power suppliers because they may have to pay costs they caused to be incurred under the prior industry regime before they are able to switch suppliers. However, this will be during a transition period only, and only with respect to a discrete set of contracts and only where the utility meets its burden of proof with respect to a particular departing customer.

We reject as misplaced IN Consumers' argument that the Open Access Rule is discriminatory because two ''similarly-situated'' customers for ''identical'' transmission services (one who previously purchased transmission bundled with its power requirements from the utility and now seeks to purchase only unbundled transmission, and the other who previously used an alternative source of supply and seeks to purchase unbundled transmission from the utility) will pay substantially different rates for the same service. The error in this argument is that the two customers in the example are *not* ''similarly-situated'' precisely because one of them was a former bundled wholesale requirements customer of the utility for whom the utility may have incurred costs to meet reasonably expected customer demand, whereas the other was never a generation customer of the utility and thus appropriately bears no cost responsibility for stranded generation costs incurred by that utility. Indeed, this example illustrates precisely the reason underlying the Commission's stranded cost mechanism. If a utility had previously served a customer as a seller of generation as well as a transmitter, it is allowed an opportunity to show that it incurred costs based on a reasonable expectation of continuing to serve the power needs of that customer beyond the contract term. Similarly, contrary to Central Illinois Light's claim, if different treatment of different customers were to occur, it would not be due to ''accidents of circumstance''—it would be the result of the conscious application by the Commission of its decision to give a utility the opportunity to recover stranded costs from a wholesale requirements customer if the utility can demonstrate that it incurred costs to provide service to the customer based on a reasonable expectation that it would continue to serve the customer after the contract term.

In response to the claims of those entities that challenge the factual record for allowing wholesale stranded cost recovery, we believe that the record in this proceeding clearly demonstrates the need to give utilities the opportunity to recover wholesale stranded costs. We have shown that the Rule's open access requirement will significantly alter historical relationships among traditional utilities and their customers. Indeed, that is one of its objectives. In the longer term, we seek to have all power supply arrangements priced by the competitive marketplace. However, utilities prudently incurred costs under a prior regulatory regime that created an expectation of an opportunity for recovery of those costs. Common sense indicates that a utility that historically supplied bundled generation and transmission services to a wholesale requirements customer and that reasonably expected to continue to serve the customer may have incurred costs to provide service to that customer that could be stranded if the customer uses open access transmission to reach a new generation supplier.[502] As we learned from our experience in restructuring of the natural gas industry, open access and unbundling did in fact exacerbate the take-or-pay problems in the gas industry because it gave customers more options. That is what we are doing in the electric industry as well. As a result, we have concluded that utilities should be permitted to seek recovery of stranded costs in certain limited and defined circumstances.

We disagree with those entities that argue that utilities have not provided sufficient data on the existence of wholesale stranded costs to justify the approach adopted by the Commission in Order No. 888. Presumably these entities would require us to calculate specific stranded cost estimates for every public utility before we could act to address this critical issue. However, where the Commission decides to act by means of a generic rule,[503] the Commission is not required to make individual findings on a utility-by-utility basis.[504] Moreover, the Rule does not say that all utilities with wholesale contract customers will be allowed to recover stranded costs, only that those utilities that have requirements contracts that were executed on or before July 11, 1994 that do not contain an exit fee or explicit stranded cost provision and that can meet the required evidentiary showing would be allowed such recovery. On this basis, our decision to give utilities the opportunity to seek stranded cost recovery for certain wholesale requirements contracts is not dependent on a showing that any particular utility will actually be eligible to recover stranded costs as a result of the open access requirement.[505]

We also will reject SC Public Service Authority's request that the Commission deny market-based rate authority for all utilities seeking stranded cost recovery. SC Public Service Authority has failed to demonstrate that the ability to seek stranded cost recovery would, by definition, eliminate the potential for mitigation of any generation or transmission market power. If an entity believes that a utility seeking market-based rate authority does not satisfy the Commission's criteria for the grant of market-rate authority (*e.g.*, because the utility has, or has failed to mitigate, market power in generation or transmission), that entity will have ample opportunity to present its case in the market-based rate proceeding.

American Forest & Paper's objection that utilities that voluntarily filed open access tariffs cannot utilize the stranded cost provisions and therefore that only utilities who were forced to offer open access transmission are being rewarded is misplaced. First, there is nothing in Order No. 888 that prohibits a utility that voluntarily filed an open access transmission tariff from seeking recovery of stranded costs if it can demonstrate a reasonable expectation of continuing to serve a particular wholesale customer beyond the term of its existing contract. Second, many of the ''open access'' tariffs accepted prior to Order No. 888, while an improvement upon the status quo of no access, did not contain the minimum terms and conditions of non-discriminatory service, including functional unbundling. Order No. 888 required utilities that tendered for filing open access tariffs prior to the issuance of the Rule (Group 1 public utilities) to make section 206 compliance filings that

[502] As the *AGD* court noted: ''Agencies do not need to conduct experiments in order to rely on the prediction that an unsupported stone will fall.'' 824 F.2d at 1008.

[503] As we noted in Order No. 888, there is no question that it is within the Commission's discretion to decide whether to act through rule or through case-by-case adjudication. FERC Stats. & Regs. at 31,679; *mimeo* at 127–28.

[504] *See AGD*, 824 F.2d at 1008.

[505] Indeed, we are somewhat puzzled by the argument that we may not act in the absence of ''hard data'' that the potential stranded cost problem is widespread and huge. Here we provide only the opportunity to seek stranded cost recovery for a concededly narrow subset of cases that we believe may give rise to a valid claim for extracontractual recovery. If as petitioners suggest the problem is modest and confined to a small number of utilities, the evidentiary process will sort that out, and the potential effect on departing customers and on the pace of competition will be similarly modest.

contain the non-rate terms and conditions set forth in the Open Access Rule pro forma tariff. That tariff expressly includes provisions allowing a transmission provider to seek to recover stranded costs in accordance with the terms, conditions and procedures set forth in Order No. 888. Of the 101 public utilities that had some version of open access available prior to Order No. 888, all now have open access tariffs on file that contain provisions that expressly allow the transmission provider to seek to recover stranded costs as provided in Order No. 888.

We also will decline San Francisco's request that the Commission include ''exercise of pre-existing contract rights for transmission and designation of wholesale loads'' or similar language as an example of a situation for which stranded costs may not be sought.[506] We are not prepared to make individual factual determinations in the context of this Rule.[507] As specific requests for stranded cost recovery are presented to the Commission, they will be addressed based on the facts presented and the merits of the particular request.

Rehearing Requests Seeking Broader Stranded Cost Recovery

In sharp contrast to the entities seeking rehearing of the Commission's decision to allow stranded cost recovery, other entities ask the Commission to expand the scope of the stranded cost recovery allowed by Order No. 888. Various entities ask that the scope of stranded cost recovery be expanded to include situations in which the departing customer does not take unbundled transmission from the former supplier and in which previously existing municipal utilities annex additional territory or otherwise expand.[508] These entities disagree with the Commission's analysis in Order No. 888 that the opportunity to seek recovery should be precluded in situations in which the departing wholesale customer ceases to purchase power from the utility but does not use the utility's transmission system to reach another supplier. The Commission excluded these situations because the costs would not be stranded as a result of the Commission's open access transmission requirement, but rather as a result of the exercise of a preexisting competitive option. The entities argue on rehearing that such costs are attributable to the Commission's efforts to restructure the wholesale power market. Several argue that there is no good policy reason for addressing stranded costs only where linked directly to the Open Access Rule or section 211 orders because a variety of federal actions, not just the Open Access Rule and section 211 orders, have created a competitive wholesale power market and the specter of stranded costs caused by customers departing their traditional utility. They contend that, but for the Commission's creation of a vibrant power market, EPAct, and other pre-Order No. 888 efforts by the Commission to expand transmission access, the preexisting options would not have been (and historically were not) exercised.

Puget argues that even when a departing customer can import its new power supply without using its former supplier's transmission system, it frequently will be the case that the power supply would not be available to the customer if open access transmission rules were not in place to permit that power to move from distant generators over intervening utilities' transmission facilities.[509]

EEI expresses concern that strict application of the ''but for open access'' test would create new incentives to evade stranded cost recovery.[510] According to EEI, the Rule would deny recovery for costs stranded pursuant to a voluntarily negotiated transmission service agreement, but would permit recovery if such agreement were ordered pursuant to FPA section 211. In this manner, EEI contends that the Rule will discourage parties from settling transmission disputes. It says that any transmission agreement negotiated under ''the threat'' of section 211 should be entitled to stranded cost recovery if providing service results in the stranding of legitimate and prudent costs.

PSE&G and Carolina P&L express concern that denying stranded cost recovery where the departing customer does not use the former supplier's transmission system will create an artificial incentive to build ''contract path'' lines designed to thwart stranded cost recovery. They maintain that the existence of alternative transmission paths should not be a bar to stranded cost recovery where the departing customer avails itself of the Commission's *Mobile-Sierra* finding permitting customers to challenge the terms of their contracts under the just and reasonable standard. They assert that, notwithstanding the availability of alternative transmission, the only way that the customer could have availed itself of the *Mobile-Sierra* finding was as a result of the Commission's Open Access Rule.

Several entities contend that the FPA's requirement of just and reasonable rates and the Fifth Amendment's requirement to avoid confiscation require the Commission to address stranded costs that result when a departing customer does not use the former supplier's transmission system or that result from municipal annexation.[511] According to Puget, the ultimate Constitutional test will be whether Order No. 888 will afford a fair overall return on all prudent utility investments under the Constitutional standards set forth by the Supreme Court.[512] Coalition for Economic Competition submits that, as was the case in the context of the unbundling of natural gas pipelines, the Commission cannot ignore stranded costs resulting from the unbundling of electric services and should acknowledge its Constitutional obligations to address the recovery of all stranded costs, including those that result from municipal expansion and those that result when a

[506] In making this determination we do not decide whether such situations demonstrate the presence or lack of a reasonable expectation of continuing to serve a customer after the expiration of an existing wholesale requirements contract (*i.e.*, one that was executed on or before July 11, 1994).

[507] San Francisco will have sufficient opportunity to raise the argument in any PG&E stranded cost recovery case.

[508] *E.g.*, EEI, Coalition for Economic Competition, Puget, Centerior, Southern. The issue of expanding the rule to encompass municipal annexations and expansions is discussed in greater detail in section IV.J.6 below.

[509] Puget submits that the potential for customers not taking unbundled transmission services from their former suppliers is particularly acute in the Pacific Northwest due to BPA's ownership of much of the region's transmission facilities.

[510] NIMO contends that the Commission erred by failing to address the extent to which Order No. 888's exceptions to the general policy of full stranded cost recovery (*e.g.*, no recovery for customer use of new transmission provider or municipal annexations) create an opportunity for customers to avoid payment of part or all of their share of utility stranded costs, will enable customers to take advantage of such opportunities in ways that will reduce rather than enhance overall economic efficiency, and will deprive utilities of a reasonable opportunity to recover their prudently incurred costs or will shift costs unfairly among customers. *See also* Puget.

[511] *E.g.*, Puget, Coalition for Economic Competition, NIMO. These parties make a similar argument in the case of stranded costs that result from retail wheeling. *See* section IV.J.7 below.

[512] Puget cites in support Stone v. Farmers' Loan & Trust Company, 116 U.S. 307, 331 (1886); Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 602 (1944); and Duquesne Light Company v. Barasch, 488 U.S 299, 307–08 (1989). Puget objects that the stranded cost recovery mechanism in Order No. 888 is too narrow and too easy to circumvent; it can be denied for failure to satisfy the reasonable expectation test or based on a finding that costs are not legitimate and verifiable. Puget argues that stranded cost recovery is constitutionally required and that the recovery mechanism must be amended to ensure full recovery of prudently incurred stranded costs, including PURPA contract costs.

customer does not obtain transmission services from its former supplier.

SC Public Service Authority also asks the Commission to allow the recovery of stranded costs that result from the loss of indirect customers (*e.g.*, customers of wholesale requirements customers). It argues that if such indirect customers can get access to a new source of power through open access tariffs, the requirements of the utility's direct customer will decrease, and the supplying utility will suffer stranded costs. SC Public Service Authority states that because of the nexus between open access and the departure of the indirect customer, utilities that suffer stranded costs in the event of the loss of an indirect customer should have an opportunity to recover those costs under the reasonable expectation standard.

A number of entities also ask the Commission to find that open access transmission and stranded cost recovery are necessary to accomplish the remedy ordered by the Commission and thus are not severable.[513] To this end, they submit that if the Commission's ability to provide for stranded cost recovery is reduced or substantially modified, public utilities should be able to withdraw filed tariffs or to file amended tariffs. It is their position that deletion or substantial change of the open access or stranded cost provisions by the Commission or by a court would vitiate the basis on which the Commission premised the Rule.

In an effort to ensure that stranded cost recovery procedures do not become a vehicle for lengthy and expensive litigation over whether there is a sufficient nexus to open access, several entities ask the Commission to place on the departing generation customers the burden to demonstrate the absence of a nexus between their actions and the availability of open access transmission under the Rule in those cases where: (i) the contract has no term or termination provision; (ii) the Commission issues an order under section 206 reducing the term of the contract; or (iii) there is legitimate municipalization.[514]

Commission Conclusion

We will deny the requests for rehearing that ask us to expand the scope of stranded cost recovery to include situations in which the departing customer does not take unbundled transmission from its former supplier but instead obtains transmission from another utility or obtains power from a third party supplier who is located in the customer's service territory and thus requires no transmission from the former supplier.[515] As the Commission stated in Order No. 888, the premise of the Rule is that where the former requirements supplier had a reasonable expectation of serving beyond the contract term and the customer uses the open access transmission tariff of its former requirements supplier to obtain power from a new generation supplier, the customer must pay the costs that were incurred on its behalf under the prior regulatory regime. The Rule is not intended, however, to apply to the recovery of costs associated with the normal risks of competition, such as self-generation, cogeneration, or loss of load, that do not arise from the new, accelerated availability of non-discriminatory open access transmission. If a customer leaves its utility supplier by exercising options that could have been undertaken prior to mandatory transmission under Order No. 888 or the Energy Policy Act, or that do not rely on access to the former seller's transmission (such as access to another power supplier through another utility's transmission system or self-generation), there is no direct nexus to Commission-mandated transmission access.

For example, if a customer is able to obtain power from a new supplier by using the transmission system of another utility, it is likely that the customer could have made these arrangements in the absence of the new open access rules. The new transmission provider would have had little incentive to deny transmission services to the customer in order to protect another utility's existing power supply arrangement, since it was not the customer's power supplier in the first place. As Order No. 888 suggested, it is likely that the neighboring utility would have a positive incentive to provide the transmission service in order to increase its transmission revenues, and that this incentive is unchanged by open access transmission.[516]

Although EEI and others argue that EPAct and the Commission's pre-Order No. 888 efforts to expand transmission access have facilitated the exercise of pre-existing competitive options, the fact remains that such options historically were available before open access. For this reason, we conclude that costs incurred as a result of the exercise of pre-existing competitive options do not fall within the scope of Order No. 888.

A number of entities argue that, even where the departing customer obtains access to another power supplier through the transmission system of another utility (*i.e.*, not that of its former supplier), the power supply would not have been available to the customer if open access transmission rules were not in place to permit that power to move from distant generators over intervening utilities' transmission facilities. Some argue that there is no good policy reason for addressing stranded costs only where linked directly to the Open Access Rule (or to a section 211 order) because a variety of federal actions have created a competitive wholesale power market and the specter of stranded costs caused by customers departing their traditional utility. While these arguments may have superficial appeal, the effective result would be to provide for recovery of stranded costs from departing customers under the Rule no matter how tenuous the nexus to Commission-mandated transmission access. The Commission has to exercise reasonable judgment and reasonable line drawing regarding the link between its actions in this Rule and the decision to allow an opportunity for extra-contractual stranded cost recovery from the departing customer. The Commission believes that requiring a direct nexus between Commission-mandated transmission access (namely, requiring that the departing customer obtain access to another power supplier *through the use of its former supplier's Commission-required tariff—i.e.*, an open access tariff or a tariff ordered pursuant to section 211) and the special stranded cost recovery procedures of this Rule is the most reasoned and supportable approach because it establishes a clear link between availability of the transmission tariff

[513] *E.g.*, EEI, Oklahoma G&E, Nuclear Energy Institute, Southern. Southern requests that the Commission add a section 35.29 to the regulatory text providing: ''Sections 35.26 and 35.28 of this part constitute unseverable portions of a unitary action of the Commission.''

[514] *E.g.*, Carolina P&L, PSE&G.

[515] We discuss in Section IV.J.6 below our disposition of the rehearing requests that support recovery of costs stranded as a result of municipal annexation or expansion. In response to EEI's argument that the Rule would deny recovery for costs stranded pursuant to a voluntarily-negotiated transmission service agreement and would discourage parties from settling transmission disputes, we find EEI's arguments in support of its position to be vague and cursory. However, we do not interpret the Rule in any way as precluding parties from addressing stranded cost issues through settlement, including settlement of a transmission dispute. To the contrary, we fully expect that the renegotiation of contracts, including transmission agreements, would provide parties with a useful means for resolving stranded cost issues without litigation. We believe that a negotiated rate that includes an amount for stranded cost recovery could be found to be just and reasonable.

[516] FERC Stats. & Regs. at 31,849–50; *mimeo* at 624–26.

and the decision of the customer to seek an alternative supplier.

With regard to potential stranded costs associated with situations that could have occurred prior to the Open Access Rule and prior to the Energy Policy Act (such as self-generation), under traditional ratemaking such costs (albeit not previously labeled as potential ''stranded'' costs) would in most cases be reallocated in the next rate case to remaining customers. The fact that this Rule does not permit a utility to seek recovery of these types of costs from the departing customer does not mean that the Commission may not, in appropriate circumstances, permit their recovery through traditional ratemaking means. However, many factors will influence cost recovery in the future, including whether the utility is selling at cost-based or market-based rates and the transitional period to more competitive bulk power markets. The Commission will address these matters on a case-by-case basis.

We do not agree with those commenters who contend that the Commission's failure in Order No. 888 to allow for the recovery of costs incurred by a utility when a departing customer does not use the former supplier's transmission system to reach a new supplier would be confiscatory in violation of the Constitution. As the Supreme Court explained in *Duquesne,* ''[t]he guiding principle has been that the Constitution protects utilities from being limited to a charge for their property serving the public which is so 'unjust' as to be confiscatory.''[517] However, Order No. 888 addresses only the recovery of legitimate, prudent and verifiable costs that are stranded if a former wholesale requirements customer or a former retail customer uses a Commission-mandated transmission tariff to reach a new supplier. As discussed above, Order No. 888 does *not* by its terms bar the recovery of costs that do not result from the use of Commission-required transmission access (*i.e.,* costs that result when a departing customer does not use the former supplying utility's open access tariff). Utilities may, as before, seek recovery of such non-open access-related costs on a case-by-case basis in individual rate proceedings. The Commission will not prejudge those issues here. As a result, the argument that the Commission's treatment of stranded costs in Order No. 888 (*i.e.,* its failure to treat certain costs as costs for which recovery may be sought under the Rule) will result in rates that will be so unjust as to be confiscatory is misplaced.

We deny SC Public Service Authority's request that the Commission allow a utility to seek recovery of stranded costs that result from the loss of indirect customers (*i.e.,* the loss of the utility's customer's customers). The Commission does not believe it is appropriate or feasible to allow a public utility (or a transmitting utility under section 211 of the FPA) to seek recovery of stranded costs from an indirect customer (*i.e.,* a customer of a wholesale requirements customer of the utility). The reasonable expectation analysis would apply only to the direct wholesale customer of the utility, not to the indirect customer. A utility may seek to recover stranded costs from a direct wholesale customer (subject to the requirements of the Rule), but it is up to the direct wholesale customer, through its contracts with its customers or through the appropriate regulatory authority, to seek to recover stranded costs from its customers.

We also deny PSE&G's and Carolina P&L's request that a utility be allowed to seek stranded cost recovery in cases where the departing customer uses the Commission's *Mobile-Sierra* finding to get out of the contract under the just and reasonable standard and uses alternative suppliers and alternative transmission.[518] We disagree with their argument that the only way that the customer could have availed itself of a *Mobile-Sierra* finding was as a result of the Commission's open access rules and thus the necessary nexus is met. A customer to a *Mobile-Sierra* contract always has the option of instituting a proceeding under section 206 of the FPA and making a showing of why, under *Mobile-Sierra,* it is in the public interest to modify the contract.

We will not, at this time, make any determination whether or not the requirements of open access transmission and stranded cost recovery are severable. As we indicated in Order No. 888, we issued the Stranded Cost Final Rule simultaneously with the Open Access Rule because we believe that the recovery of legitimate, prudent and verifiable stranded costs is critical to the successful transition of the electric industry to a competitive, open access environment.[519] We believe that our decision to allow stranded cost recovery will be upheld by the courts. Moreover, as we discuss in Section IV.A.1 above, it would be premature to consider at this time what the Commission would do if one or more of the provisions of the Rule are not upheld. Circumstances at the time of any court order would dictate how we should proceed and we would consider all such circumstances, and the entirety of our policy decisions, before determining how to respond to a court decision.

Further, we decline to place on departing generation customers the burden of demonstrating that no nexus exists between their actions and the availability of open access transmission under the Rule in cases involving no term or termination provision, an order under section 206 reducing the term of the contract, or municipalization. The proponents of such a proposal, Carolina P&L and PSE&G, attempt to justify it as a means to ensure that stranded cost recovery procedures do not become a vehicle for lengthy and expensive litigation over whether there is a sufficient nexus to open access in the three identified situations. However, Order No. 888 places the burden on the utility seeking stranded cost recovery to demonstrate that the costs for which it seeks recovery fall within the scope of the Rule and that it had a reasonable expectation of continuing service. In this regard, the Rule tracks the requirement of sections 205 and 206 of the FPA that a public utility demonstrate the justness and reasonableness of its proposed rates. Carolina P&L and PSE&G fail to explain why it would be appropriate for customers (as opposed to the utilities seeking recovery) in the three identified situations to bear the initial burden of demonstrating why costs should not be recovered from them under the Rule.[520] As a result, we reject their proposal.[521]

Rehearing Requests—Stranded Cost Recovery By Transmitting Utilities That Are Not Public Utilities

A number of entities contend that the Commission's decision to limit stranded cost recovery for transmitting utilities that are not public utilities to section

[517] 488 U.S. at 307.

[518] These parties appear to refer to a situation in which a customer is able to modify or terminate its contract, but would use the transmission system of a utility other than that of its former supplier in order to reach a new generation supplier. In this circumstance, the Rule would not permit the former supplier to seek stranded costs.

[519] FERC Stats. & Regs. at 31,789–90; *mimeo* at 454–55.

[520] In addition, the proposal would not eliminate lengthy litigation. It would only change the burden of proof in whatever litigation occurs.

[521] We note, however, that in a section 206 proceeding brought by a customer seeking to shorten or terminate a contract, the customer has the burden (as it would in any section 206 case that it initiates) of presenting sufficient evidence that the contract is no longer just and reasonable. As we stated in the Rule, the utility must present any stranded cost claim at that time. *See* FERC Stats. & Regs. at 31,664, 31,813; *mimeo* at 86–87, 521–22.

211 proceedings is inconsistent with its decision to impose the reciprocity requirement on those utilities, violative of the principle of comparability, and unduly discriminatory and anticompetitive.[522] NRECA submits that if the Commission has the statutory authority to require non-public utilities to render transmission service outside of a section 211 proceeding through the reciprocity, RTG and power pool provisions of the Rule, then it must exercise that authority to ensure stranded cost recovery by such non-public utilities. Noting that the Rule does not address how a non-public utility that chooses voluntarily to provide an open access tariff can recover its stranded costs, SC Public Service Authority asks the Commission to confirm on rehearing that non-jurisdictional utilities can include a provision for recovery of stranded costs in their tariffs provided pursuant to the Final Rule.

Commission Conclusion

The Commission's jurisdiction over the recovery of stranded costs by non-public utilities, and thus our ability to permit an opportunity for recovery of such costs, is limited by statute. While we have the statutory authority to ensure that non-public utilities have the opportunity to seek recovery of stranded costs in proceedings under sections 211 and 212 of the FPA,[523] we do not have such authority under sections 205 and 206 of the FPA. However, we clarify that nothing in the Final Rule was intended to preclude non-public utilities from including stranded cost provisions in voluntary reciprocity tariffs or from otherwise recovering stranded costs under applicable law. We discuss these matters in detail below.

As we stated in Order No. 888 in response to commenters' objections that the Rule would give public utilities a greater opportunity than other transmitting utilities to recover stranded costs, our jurisdiction over transmitting utilities that are not also public utilities is limited. If the selling utility is a transmitting utility that is not a public utility, its power sales contracts are not subject to this Commission's jurisdiction under sections 205 and 206 of the FPA. Thus, we can provide such a transmitting utility an opportunity to recover stranded costs only through Commission-jurisdictional transmission rates fixed under sections 211 and 212 of the FPA.[524]

The open access tariff reciprocity provision, which applies to all open access customers that own, operate, or control transmission facilities or are affiliates of entities that own, operate or control such facilities, and that do not obtain a waiver of the provision, does not create jurisdiction for the Commission to fix the rates for these utilities. Contrary to the suggestions of some, the tariff reciprocity provision is not based on any statutory authority of the Commission to require non-public utilities to render transmission service outside of a section 211 proceeding. As we make clear in Order No. 888, we do not have authority under sections 205 and 206 of the FPA to require non-public utilities to file tariffs (or rate schedules for that matter) with the Commission.[525] In permitting a public utility to deny transmission service to any person that requests service under an open access tariff unless that person provides reciprocal non-discriminatory transmission services to the transmission provider, we are not acting under any statutory authority to require non-public utilities to provide transmission access. Rather, out of fairness, we are conditioning the use of open access services by all customers, including non-public utilities, on an agreement to offer comparable transmission services in return to the public utility transmission provider.[526]

We clarify that a non-public utility that chooses voluntarily to offer an open access tariff for purposes of demonstrating that it meets the reciprocity provision can include a stranded cost provision in its tariff. However, adjudication of any stranded cost claims under that tariff is not subject to the Commission's jurisdiction.[527] With the exception of our section 210 interconnection and sections 211–212 transmission rate jurisdiction, we do not have jurisdiction over the rates of non-public utilities. If a non-public utility wishes to recover stranded costs pursuant to a tariff or otherwise, it can seek to do so subject to the review of the appropriate regulatory authority.[528]

Rehearing Requests—Stranded Cost Recovery for Transmission Dependent Utilities

NRECA and TDU Systems challenge the Commission's decision not to guarantee a transmission dependent utility that is not a public utility stranded cost recovery when the transmission dependent utility's customers leave its system by using the open access tariff of another utility. They submit that the ability of transmission dependent utilities to compete with public utility transmission providers in an open access environment would be severely affected by their inability to recover stranded costs on a basis comparable to those transmission providers. They argue that the open access provisions of Order No. 888 will result in the stranding of costs incurred by non-transmission owning, non-public utilities to serve customers that depart to other suppliers. They contend that these customers are already located in close proximity to, and interconnected to, public utilities; thus it is likely that they would use the open access tariffs of these public utilities to obtain their new power supplies. NRECA and TDU Systems argue that this situation should meet the ''but for open access'' nexus. On this basis, they assert that Order No. 888 is no less the proximate cause of the departure of customers of transmission dependent utilities than it is of the departure of public utility transmission owners' customers. They object that the Commission takes no account of the anticompetitive effects of disregarding costs stranded on transmission dependent utilities' systems as a result of open access.

Dairyland Coop asks the Commission to recognize a generation and transmission (G&T) cooperative and its member distribution cooperatives as a single economic unit for purposes of stranded cost recovery (such that conversion of a distribution

[522] *E.g.*, NRECA, TDU Systems, Dairyland Coop.

[523] Stranded costs could also conceivably arise as a result of an ordered interconnection under section 210. However, the rates for such an interconnection would be established pursuant to section 212 and could therefore also include stranded costs.

[524] FERC Stats. & Regs. at 31,791; *mimeo* at 458. If such a transmitting utility seeks stranded cost recovery in a proceeding under sections 211 and 212, it would, consistent with the provisions of the Rule, be limited to recovery associated with requirements contracts executed on or before July 11, 1994 that do not contain an exit fee or other explicit stranded cost provision.

[525] FERC Stats. & Regs. at 31,691; *mimeo* at 162.

[526] FERC Stats. & Regs. at 31,760–62; *mimeo* at 370–74.

[527] Although the Commission would not determine the rate, including the stranded cost component of the rate, of a non-public utility, we would review a public utility's claim that it is entitled to deny service to a non-public utility because the stranded cost component of the non-public utility's transmission rate is being applied in a way that violates the principle of comparability.

[528] We note that in the case of stranded cost claims presented to the Commission by BPA or one of the other PMAs, our review would be limited to that set forth in the applicable statutes and any relevant delegation of authority from the Secretary of Energy. *See, e.g.*, Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § 839–839h (1985) (Northwest Power Act); Department of Energy Delegation Order No. 0204–108, as amended, 48 FR 55,664 (1983), amended, 51 FR 19,744 (1986), amended, 56 FR 41,835 (1991), amended, 58 FR 59,716 (1993) (delegation order relating to Western Area Power Administration).

cooperative's retail customer to a wholesale customer may result in stranded costs for the G&T cooperative). It objects that the Commission implicitly rejected comments to this effect without discussion in Order No. 888.

Commission Conclusion

We deny the requests for rehearing of our decision not to permit transmission dependent utilities and electric cooperatives to seek stranded cost recovery unless they are public utilities or transmitting utilities that would otherwise qualify under the Rule. With regard to transmission dependent utilities, as we indicated in Order No. 888, the limited opportunity for stranded cost recovery contained in the Rule would not likely apply in the case of transmission dependent utilities, who own little or no transmission and the majority of whom would not be public utilities or transmitting utilities subject to the Commission's jurisdiction.[529] The opportunity for extra-contractual wholesale stranded cost recovery is allowed only where the departing customers use open access (or section 211 access) on the transmission systems of their former generation suppliers and only for a discrete set of requirements contracts executed on or before July 11, 1994 that do not contain explicit stranded cost provisions (involving the bundled provision of generation and transmission) and retail-turned-wholesale situations for which the utility can demonstrate that it had a reasonable expectation of continuing service. Even though it may be the case that transmission dependent utilities lose generation customers that are able to use open access tariffs of other utilities to reach new suppliers, there was nothing to keep these other utilities from offering such transmission service before Order No. 888. These other utilities had no economic incentive to deny such service before Order No. 888. Thus, in the scenario posited in the rehearings, the transmission dependent utilities do not meet the fundamental premise of the Rule: that a utility that historically has supplied bundled generation and transmission services to a wholesale requirements customer and incurred costs to meet reasonably expected customer demand should have an opportunity to recover legitimate, prudent and verifiable costs that may be stranded because open access use of the utility's transmission system enables a generation customer to shop for power.[530]

However, this is not to say that a transmission dependent utility that is not a public utility, or other non-public utility entities (such as RUS-financed cooperatives), cannot seek recovery of the cost of any resulting uneconomic assets through their contracts with their customers or through the appropriate regulatory authority. The Commission has no objection to these entities being able to seek such cost recovery through the appropriate regulatory channels. However, because the Commission does not have jurisdiction over these entities (other than through sections 211 and 212 in the case of non-public utility transmitting utilities), it does not have authority to allow them to recover these costs.[531]

We also deny Dairyland Coop's request that the Commission recognize a G&T cooperative and its member distribution cooperatives as a single economic unit for purposes of stranded cost recovery. If a cooperative obtains its financing through RUS, it is not a public utility subject to our jurisdiction under sections 205 and 206 of the FPA. Although the Commission has no objection to these G&T cooperatives being able to seek cost recovery (including recovery of costs on behalf of their distribution cooperatives) through the appropriate regulatory channels, this Commission does not have authority to allow them to seek recovery of stranded costs unless access is obtained through a section 211 order.[532]

In the case of a G&T cooperative that is a public utility (of which there are just a handful at the present time), such a cooperative would have to have a jurisdictional wholesale requirements contract with its distribution cooperative in order to be able to seek recovery of stranded costs under the Rule. In the case of a jurisdictional G&T cooperative, the request that the G&T be treated as a single economic unit with the distribution cooperative (such that departure of a distribution cooperative's retail customer would be treated as resulting in stranded costs for the G&T cooperative for which the G&T could seek recovery) is, in effect, a request for recovery of stranded costs from an indirect customer. As we discuss above, the Commission does not believe it is appropriate or feasible to allow a public utility (or a transmitting utility under section 211 of the FPA) to seek recovery of stranded costs from an indirect customer (*i.e.*, a customer of a wholesale requirements customer of the utility) under this Rule. The reasonable expectation analysis would apply only to the direct wholesale customer of the utility, not to the indirect customer. It is up to the direct wholesale customer of the utility, through its contracts with its customers or through the appropriate regulatory authority, to seek to recover such costs from its customers.

Commenters have provided no basis for making an exception in the case of cooperatives. Moreover, to treat a G&T cooperative and its member distribution cooperatives as a single economic unit for stranded cost purposes would be inconsistent with the Commission's decision not to treat cooperatives as a single unit for purposes of Order No. 888's reciprocity provision.

In Order No. 888, in response to arguments raised by cooperatives, the Commission agreed to limit the reciprocity requirement to corporate affiliates. In other words, if a G&T cooperative seeks open access transmission service from the transmission provider, only the G&T cooperative (not its member distribution cooperatives) would be required to offer transmission service. If a member distribution cooperative itself receives transmission service from the transmission provider, then it (but not its G&T cooperative) must offer reciprocal transmission service over its interstate transmission facilities, if any.[533] Dairyland has provided no basis to support treating cooperatives differently for stranded cost purposes and reciprocity purposes. We accordingly will deny Dairyland's request for rehearing on this issue.

Rehearing Requests Opposing Limitation of Recovery to Wholesale Requirements Customers

PA Munis argues that it is inequitable and anticompetitive for ''wholesale requirements customers'' but not other ''wholesale customers'' to have to pay stranded costs, repeating an argument that it made in its comments on the supplemental stranded cost NOPR. It says that there is no difference in the firm power provided by public utilities

[529] FERC Stats. & Regs. at 31,790; *mimeo* at 456–57.

[530] FERC Stats. & Regs. at 31,790; *mimeo* at 456–57.

[531] Unless these entities own some transmission used in interstate commerce or are engaged in sales for resale, and are not otherwise exempt under FPA section 201(f), they would not be public utilities under sections 205 and 206. Most transmission dependent utilities are not public utilities.

[532] A G&T cooperative that is a transmitting utility could seek recovery of stranded costs if it is ordered to provide transmission services that permit its distribution cooperative to reach another supplier and if it had a requirements contract with the distribution cooperative that was executed on or before July 11, 1994.

[533] FERC Stats. & Regs. at 31,763; *mimeo* at 377–78.

to ''wholesale requirements customers'' and to ''wholesale customers'' and no difference in the generating facilities required and the costs of operation between the production of firm capacity and energy required for ''wholesale requirements sales'' and ''wholesale sales.'' PA Munis submits that the total amount of wholesale requirements power purchased in the United States is less than two percent of the total amount of firm power sales. It argues that requiring only wholesale requirements customers to pay stranded costs would restrict the ability of such customers to switch suppliers while not similarly restricting large firm wholesale customers. It contends that wholesale firm requirements customers therefore will not have equal access under the Rule because of the increased transmission rates for stranded costs that would not be levied on other large wholesale firm customers. Pa Munis says this produces the same result found unlawful in the *Maryland People's Counsel* case[534]—equal access to all wholesale customers is virtually denied by the chilling effect of stranded costs borne only by wholesale requirements customers.

Commission Conclusion

In Order No. 888, the Commission fully addressed the concerns of PA Munis. We again address below the major distinctions between requirements and other customers and deny rehearing.

In Order No. 888, we explained that the historical and practical relationship between a utility and its wholesale requirements customers, including the expectation of continued service, justifies allowing public utilities the opportunity to seek to recover the stranded costs covered by this Rule from only those customers and not from non-requirements customers that contract separately for transmission services to deliver their purchased power or from wholesale customers that purchase non-requirements power. Requirements customers historically were long-term customers who by definition depended upon their local suppliers because they were captive customers. Utilities had no obligation to provide transmission service that would allow these customers to reach other suppliers, and there were no other transmission facilities in proximity to those of the supplying utility. And the service involved requirements power; that is, these customers were dependent upon the wholesale supplier for all or part of their power. Utilities thus assumed they would continue serving these customers and may have made significant investments based on that long-term expectation. These same assumptions cannot be made for short-term, non-firm transactions and other wholesale non-requirements firm transactions. Unlike requirements customers, these customers had other options. Thus, the supplying utility could not assume that these customers would remain on its system.

With regard to short-term transactions, utilities did not (and do not today) generally make investments for short-term economy-type transactions. Rather, such transactions were entered into only when the utility temporarily had available capacity or energy that could be provided to the buyer at a price higher than the seller's incremental cost and lower than the buyer's decremental cost. The utility was not obligated in any way—either explicitly or implicitly—to provide for the needs of coordination customers. Because coordination transactions were not the cause of stranded investment decisions, it would be inappropriate to allocate such costs to non-requirements customers.[535]

With regard to long-term, non-requirements firm transactions, such as unit power sales contracts, we note that there was no implied obligation to serve customers to these transactions as there was for requirements customers. Generating units were not built for the purpose of entering into these arrangements. Therefore, because utilities did not incur costs on behalf of non-requirements firm power sales customers, such customers have not caused costs to be stranded and should not be required to pay stranded cost charges. Accordingly, we reaffirm limiting the opportunity for stranded cost recovery to costs associated with wholesale requirements contracts.[536]

We recognize PA Munis' concern that if a utility meets the evidentiary requirements of the Rule and is allowed to recover stranded costs from wholesale requirements customers, such customers may see little or no savings *in the short-term* by switching power suppliers, since a stranded cost charge (in the form of either an exit fee or a surcharge on transmission) would be paid in addition to the power price paid a new supplier. However, as we discuss above and in Section IV.J.2 below, we believe that stranded costs are transition costs that must be addressed at an early stage if we are to fulfill our regulatory responsibilities in moving to competitive markets. Further, as we explain in Section IV.J.3 below, although spreading the costs to all transmission users of a utility's system (rather than imposing them directly on the departing wholesale requirements customer) might enable the customer to see earlier power cost savings than would result if stranded costs were directly assigned to the customer, we have concluded that this potential benefit to a broad-based approach is outweighed by a significant countervailing disadvantage—namely, the violation of the cost-causation principle of ratemaking. The Commission rejects a broad-based approach for the electric industry primarily because the potential power cost savings to the departing generation customer would be realized only by shifting costs that are directly attributable to the departing generation customer to the other users of the utility's transmission system.

Contrary to PA Munis's claim, we believe that the circumstances surrounding the opportunity to seek stranded cost recovery from wholesale requirements customers that is permitted in Order No. 888 are distinguishable from the issues that were before the court in the *Maryland People's Counsel* cases. Those cases involved challenges to Commission orders that permitted pipelines to transport gas at lowered prices to ''non-captive consumers'' (large industrial end users capable of switching to alternative fuels) without any obligation to provide the same service to ''captive consumers'' such as local distribution companies and their residential customers. In *Maryland People's Counsel I*, the court invalidated the Commission's authorization of a ''special marketing program'' under which a pipeline and its producer would agree to amend their high-priced gas purchase contract to permit the producer to sell the committed gas elsewhere at market prices and to credit the volume of such sales against the pipeline's high-priced purchase obligations. Eligibility to purchase the

[534] *Maryland People's Counsel* v. *FERC*, 761 F.2d 780 (D.C. Cir. 1985) (*Maryland People's Counsel I*). *See also* Maryland People's Counsel v. *FERC*, 761 F.2d 768 (D.C. Cir. 1985) (*Maryland People's Counsel II*).

[535] FERC Stats. & Regs. at 31,790–91; *mimeo* at 457–58.

[536] We clarify, however, that a contract may meet our definition of wholesale requirements contract even though it does not carry the label ''requirements contract.'' The definition refers to a contract that provides any portion of a customer's bundled wholesale power requirements. As discussed above, whether or not a contract meets this definition hinges upon whether the customer depended upon the wholesale supplier for all or part of its power because it could not obtain transmission access to reach other suppliers, *i.e.*, it was captive to the historical local supplier.

cheaper released gas was limited to industrial users. The court found that the Commission had failed to provide a reasonable basis for its decision to exclude ''captive customers'' from eligibility to purchase the cheaper released gas.[537] In *Maryland People's Counsel II*, the court invalidated the Commission's approval of blanket authority for interstate transportation of natural gas sold directly by producers to fuel-switchable end users. The court held that the Commission had failed to consider the anticompetitive effects of failing to require the pipelines to provide the same service to captive consumers on nondiscriminatory terms.[538]

In contrast to the *Maryland People's Counsel* cases, the Commission in Order No. 888 is not discounting services for one class of customers to the exclusion of another, nor is it ordering that public utilities provide transmission access to only a specified customer group. To the contrary, Order No. 888 requires all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to provide open access transmission to any ''eligible customer,'' with ''eligible customer'' defined broadly to include ''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.'' [539] Among other things, Order No. 888 gives wholesale requirements customers that previously were captive customers of their public utility suppliers the opportunity at the expiration of their contracts to take unbundled transmission service from their former suppliers in order to reach new suppliers. At the same time, the Commission recognizes that the departure of a wholesale requirements customer in this circumstance may strand costs that the former supplying utility incurred based on a reasonable expectation that it would continue to serve the customer beyond the contract term. As a result, Order No. 888 gives the former supplying utility the *opportunity* to seek recovery of costs stranded by the wholesale requirements customer's departure.

In further contrast to the *Maryland People's Counsel* cases, the Commission addresses in this Order (above) PA Munis' claim that it is inequitable and anticompetitive that only wholesale requirements customers and not other wholesale customers are subject to the stranded cost provisions of Order No. 888. The Commission has explained in detail the rationale for its decision that public utilities should be allowed an opportunity to seek to recover the stranded costs covered by this Rule only from wholesale requirements customers. The Commission has also addressed in Section IV.J.2 below the concerns expressed by some as to the potential anticompetitive effect of stranded cost charges.

Rehearing Request—ERCOT

The TX Com [540] asks the Commission to clarify that ERCOT utilities may not use a section 211 proceeding as a vehicle to obtain wholesale or retail stranded cost recovery. [541] It notes that based on the definitions in section 35.26 of ''wholesale stranded cost'' [542] and ''wholesale transmission service,'' [543] the Rule applies only to interstate service and does not apply to the intrastate service provided by the utilities within ERCOT, yet the Commission suggests that it might permit a utility in ERCOT to recover stranded costs in a section 211 proceeding. Even if the Commission concludes that it has the authority to resolve stranded cost issues for ERCOT utilities, TX Com asks the Commission to establish a preference for resolution of transmission and stranded cost issues in ERCOT by TX Com. It suggests that uncertainty and gaming as to the choice of a forum could be avoided by executing a Memorandum of Understanding between TX Com and the Commission that would require interested persons to submit disputes to TX Com. Further, to the extent that the new ERCOT transmission access rules adopted by the TX Com may be deemed as the cause of stranded costs in ERCOT, TX Com asserts that it should be allowed to resolve issues related to such stranded costs.

Commission Conclusion

In *City of College Station, Texas*,[544] the Commission repeated its view, first articulated in 1979, that sections 211 and 212 of the FPA clearly give the Commission jurisdiction to order transmission services within ERCOT, subject to the special rate provision for ERCOT utilities in section 212(k).[545] The Commission indicated that if it issues a final order in that case setting rates for transmission services within ERCOT, it will comply with section 212(k) and give deference to the TX Com's ratemaking methodology insofar as practicable and consistent with section 212(a).

Our jurisdiction to order transmission services within ERCOT includes the authority to address costs that are stranded by a section 211 transmission order.[546] Consistent with the special rate provision in section 212(k), we clarify

[537] *See* 761 F.2d 768.

[538] *See* 761 F.2d at 781–82.

[539] Pro Forma Open Access Transmission Tariff, section 1.11.

[540] TX Com's request for rehearing was filed out-of-time on May 29, 1996 with a request that the Commission accept the rehearing request for filing as of May 24, 1996. TX Com explains it had made arrangements with a courier company to pick up its rehearing request on May 23, 1996 and deliver and file the rehearing request with the Commission before 5 p.m. on May 24, 1996. TX Com states that the courier company failed to pick up the rehearing request on May 23 as previously arranged. TX Com says that when it became aware on May 24 that its rehearing request was not enroute to the Commission, it faxed a copy of the rehearing request to a copier and delivery service in Washington, D.C. The pleading, which was not signed, was delivered to the Commission prior to 5 p.m. on May 24. TX Com states that Commission personnel rejected the filing apparently because it was not signed. TX Com asks that the Commission find good cause under Rule 2001 of the Commission's Rules of Practice and Procedures, 18 CFR 385.2001 (1996), to accept its rehearing request for filing as of May 24, 1996. Under the circumstances, we will accept the rehearing request for filing as of May 24, 1996.

[541] Texas Utilities Electric Company filed on June 21, 1996 a motion for leave to file and response to TX Com's rehearing request. Texas Utilities opposes TX Com's positions on rehearing. While answers to requests for rehearing generally are not permitted, 18 CFR 385.213(a)(2) (1996), we will depart from our general rule because of the significant nature of this proceeding and will accept Texas Utilities' response.

[542] ''Wholesale stranded cost'' is defined as ''any legitimate, prudent and verifiable cost incurred by a public utility or a transmitting utility to provide service to: (1) a wholesale requirements customer that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility; or (ii) a retail customer, or a newly created wholesale power sales customer, that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility.'' Order No. 888, *mimeo* at 768.

[543] ''Wholesale transmission services'' is defined as ''ha[ving] the same meaning as provided in section 3(24) of the Federal Power Act (FPA): the transmission of electric energy sold, or to be sold, at wholesale in interstate commerce.'' Order No. 888, *mimeo* at 768.

[544] 76 FERC ¶ 61,138 (1996).

[545] Section 212(k), added by EPAct, provides as follows: (1) RATES.—Any order under section 211 requiring provision of transmission services in whole or in part within ERCOT shall provide that any ERCOT utility which is not a public utility and the transmission facilities of which are actually used for such transmission service is entitled to receive compensation based, insofar as practicable and consistent with subsection (a), on the transmission ratemaking methodology of the Public Utility Commission of Texas. 16 U.S.C. § 824k(k) (1994).

[546] To clarify that the Order No. 888 stranded cost provisions apply to the intrastate utilities within ERCOT, solely in the context of a section 211 proceeding, we will revise the definition of ''wholesale transmission services'' in section 35.26(b)(3) to read: ''*Wholesale transmission services means* the transmission of electric energy sold, or to be sold, at wholesale in interstate commerce or ordered pursuant to section 211 of the Federal Power Act (FPA).''

that we will give deference to the TX Com's ratemaking methodology, including any provisions or procedures related to stranded cost recovery, insofar as it is practicable and consistent with section 212(a) and consistent with the principle of comparability set out in Order No. 888.

2. Cajun Electric Power Cooperative, Inc. v. FERC [547]

In Order No. 888, the Commission explained why it does not interpret the *Cajun* court decision as barring the recovery of stranded costs and why the record developed in this generic proceeding fully addresses the court's concerns regarding meaningful access to alternative suppliers.[548]

We also addressed the court's concern that the method of recovery in that case (a charge in the departing customer's transmission rate) might constitute an anticompetitive tying arrangement. We explained that the stranded cost recovery procedure we prescribe in the Open Access Rule is only a transitional mechanism that is intended to enable utilities to recover costs prudently incurred under a different regulatory regime. The purpose and effect of the stranded cost recovery mechanism that we approved in the Rule is to facilitate the transition to competitive wholesale power markets. We concluded that while stranded cost recovery may temporarily delay some of the benefits of competitive bulk power markets for some customers, such transition costs must be addressed at an early stage if we are to fulfill our regulatory responsibilities in moving to competitive markets.

In reaching these conclusions, the Commission applied the traditional regulatory concept of cost causation. We stated that it is not an illegal tying arrangement to hold a customer accountable for the cost consequence of leaving an incumbent supplier if, under our rules, the incumbent supplier must show a reasonable expectation of providing continuing service to that customer before it can recover stranded costs from the customer.

In addition, in response to the *Cajun* court and commenters in this proceeding as to the need to provide as much certainty as possible for departing customers concerning their potential stranded cost obligation, the Commission included a formula for calculating a departing customer's potential stranded cost obligation. We explained that the revenues lost formula is designed to provide certainty for departing customers and to create incentives for the parties to address stranded cost claims between themselves without resort to litigation.

Rehearing Requests Arguing That the Commission Has Not Resolved the Cajun Court's Concerns

Several entities submit that the Commission has not resolved the *Cajun* court's tying concerns. They argue that tying arrangements are still the essence of the stranded cost recovery method mandated by Order No. 888, and that a tying arrangement is a *per se* antitrust violation that is not subject to justification by reference to the reasons for the restraint or the expected ancillary benefits.[549] A number of these entities object that the Commission does not address the court's substantive concern that a stranded cost provision is the antithesis of competition.[550] Several object that the Commission brushes aside the acknowledged anticompetitive effects of the rule as being ''transitional only,'' suggesting that short-term anticompetitive impacts are acceptable as long as the Commission is doing something that will be good for customers in the long term.[551] They also contend that the anticompetitive effects would not be limited to a transitional period, or that the transitional period could last indefinitely, thereby diluting or even nullifying the benefits of competition for years to come.[552]

Several entities submit that the Commission erred in concluding that the stranded cost rules contained in Order No. 888 would allow customers ''meaningful'' access to alternative power suppliers.[553] Among other things, these entities contend that there is no showing in the Order that transmission providers will not continue to exercise monopoly power over their transmission systems and that competition in generation will not be stifled by the stranded cost recovery mechanism.

Some entities also object that the stranded cost procedures contained in Order No. 888 fail to provide certainty in the computation of recoverable stranded costs. They argue that the prospect of stranded cost liability and related litigation add costs of potential deal-killing magnitude to any power supply acquisition considered by a customer.[554]

APPA and ELCON challenge the Commission's description of *Western Resources, Inc.* v. *FERC* [555] as affirming the Commission's ability to allow stranded cost recovery. APPA argues that *Western Resources* does not justify the stranded cost provisions of Order No. 888 because it was a filed rate doctrine case, not a stranded cost case. APPA says that *Western Resources* involved no consideration of any allegation of anticompetitive conduct and no allegation that the utilities' proposal constituted an illegal tying arrangement.

Commission Conclusion

We will deny the requests for rehearing advanced on the basis of the *Cajun* case. We disagree with those entities that contend that the Commission has not resolved the *Cajun* court's tying concerns. As an initial matter, we note that the parties that have raised this issue on rehearing ignore the fact that while this Commission has a responsibility to consider the anticompetitive effects of regulated aspects of interstate utility operations,[556] it has other statutory and regulatory public interest considerations which it must balance in order to engage in reasoned decisionmaking. In this proceeding, we have carefully balanced our responsibilities to remedy undue discrimination and to consider anticompetitive effects, our goal to eliminate market power of utilities and anticompetitive effects in the long run, and the need to provide a transition to competitive markets that is fair, that maintains a stable electric utility industry, and that recognizes the obligations incurred in a past, non-competitive regulatory regime. As discussed below, we do not believe that the stranded cost proposal adopted in the Rule results in an illegal tying arrangement, as argued on rehearing. We believe we have given reasoned consideration to any potential transitory

[547] 28 F.3d 173 (D.C. Cir. 1994) (*Cajun*).

[548] FERC Stats. & Regs. at 31,793–95; *mimeo* at 464–70.

[549] *See, e.g.,* ELCON, Suffolk County, Central Illinois Light, American Forest & Paper, TDU Systems, Blue Ridge, Nucor, IN Consumer Counselor, IN Consumers, APPA, PA Munis, VT DPS, Valero.

[550] *E.g.,* Central Illinois Light, American Forest & Paper.

[551] *E.g.,* American Forest & Paper, PA Munis.

[552] *E.g.,* American Forest & Paper, Occidental Chemical, PA Munis.

[553] *E.g.,* Arkansas Cities, IN Consumer Counselor, IN Consumers, Occidental Chemical, PA Munis.

[554] *E.g.,* APPA, Arkansas Cities.

[555] 72 F.3d 147 (D.C. Cir. 1995) (*Western Resources*).

[556] The Commission's power under the FPA carries with it the responsibility to consider, in appropriate circumstances, the anticompetitive effects of regulated aspects of interstate operations pursuant to sections 202 and 203, and under like directives contained in sections 205, 206, and 207. Gulf States Utilities Company v. FPC, 411 U.S. 747 (1973). While the Commission lacks principal responsibility for implementing antitrust policy, it retains an obligation to give reasoned consideration to the bearing of antitrust policy on matters within its jurisdiction. Alabama Power Company, *et al.* v. FPC, 511 F.2d 383 (D.C. Cir. 1974).

anticompetitive effects of our stranded cost policy and that we have met the directives of the court in *Cajun*.

In considering the *Cajun* decision, it is important to note that the *Cajun* court assumes the presence of a competitive market in the electric utility industry, but such a competitive market does not now exist. Instead, the Commission is in the process of trying to bring about a competitive market and to manage the transition thereto.[557] When the Commission undertook a similar restructuring in the gas industry, the D.C. Circuit invalidated the Commission's efforts precisely because the Commission had failed to deal with the stranded cost problem in a satisfactory manner.[558]

As we indicated in Order No. 888, we do not believe it is an illegal tying arrangement to hold a customer accountable for the consequences of leaving an incumbent supplier if, before the incumbent supplier can recover legitimate, prudent and verifiable stranded costs from the departing customer, it must show that it incurred costs to provide service to the customer based on a reasonable expectation of continuing to serve the customer. Order No. 888 provides no guarantee of stranded cost recovery. Moreover, Order No. 888 provides the opportunity to recover stranded costs only for a discrete set of wholesale requirements contracts—those executed on or before July 11, 1994 that do not contain an exit fee or other explicit stranded cost provision—and for retail-turned-wholesale customers. Thus, it is not necessarily the case that customers will have to pay stranded costs when they leave their current suppliers. To the contrary, before a utility can recover stranded costs from a customer, the utility must overcome certain evidentiary hurdles (including a rebuttable presumption of no reasonable expectation of continuing service if the contract contains a notice of termination provision). Particularly given the narrowly tailored circumstances under which stranded cost recovery is permissible under the Rule, we do not view it as the antithesis of competition.

We dismiss as misplaced the claims that Order No. 888's stranded cost recovery mechanism is a tying arrangement that is a *per se* antitrust violation that cannot be justified by reference to the reasons for the restraint or the expected ancillary benefits. Any ''tying'' that might result from the Rule is by regulatory order, *not* through monopoly power, and is justified as a means to avoid unfair cost shifting and to achieve the pro-competitive benefits of the Rule. As we stated in Order No. 888, the purpose and effect of the stranded cost recovery mechanism that we approve are to facilitate the transition to competitive wholesale power markets, *not* to prevent a generation customer of a utility from being able to reach alternative suppliers through its former supplier's transmission.[559]

To be sure, imposing a stranded cost charge might, in the short run, make some customers indifferent to whether they stay with their current suppliers and avoid stranded costs, or go with new suppliers but pay stranded costs to the former suppliers.[560] There is no question that, without the stranded cost recovery mechanism, some customers would be far more likely to switch to lower-cost suppliers and enjoy sooner the benefits of a competitive power market. But, as detailed in Order No. 888, such an approach may result in higher costs for other customers. We thus have had to balance the potential for earlier benefits for some customers against other public interest considerations, most particularly the need to provide a fair mechanism by which utilities can recover the costs of past investments under traditional regulatory concepts of prudently incurred costs and cost causation. The result is not to deny competitive advantages, but only to delay their full realization for some customers.

In any event, we do not believe that the Commission-imposed mechanism of allowing the utility to recover stranded costs from the departing customer through its transmission rates falls within the category of an illegal tying arrangement under the antitrust laws. As the Supreme Court has defined it, ''[a] tying arrangement is 'an agreement by a party to sell one product but only on the condition that the buyer also purchases a different (or tied) product, or at least agrees that he will not purchase that product from any other supplier.''' [561]

Here there is no ''tying'' of ''products.'' [562] Instead, the Rule provides a mechanism for recovering costs associated with a prior contract. We have not adopted a rule under which a customer may purchase transmission from a utility only on the condition that the customer also purchases a different product, namely, power, from the utility.[563] To the contrary, the Commission, through the Order No. 888 open access transmission requirement, is attempting to provide the customer with the opportunity to obtain unbundled transmission from a former supplying utility as a means to reach a new generation supplier. Whatever else, the stranded costs are not charges for ''products'' and thus there is no ''tying'' in the conventional sense. At best, there is only a condition: in obtaining unbundled transmission, the customer must also pay appropriate costs stranded by its use of Commission-required transmission access.

Finally, it is not clear how often departing customers will be obligated to pay stranded costs. Stranded cost recovery is by no means guaranteed under the Rule, nor is it clear what portion of a utility's uneconomic investment will be recoverable as stranded costs. Even when a utility is able to meet the evidentiary standard and the Commission approves imposition of a stranded cost charge, the customer is free to pay off its obligation immediately. If it chooses to pay off the stranded cost obligation over time, that charge would not be imposed indefinitely on the customer. We have limited the scope of contracts and costs for which utilities may seek stranded cost recovery. This limitation—to certain contracts and demonstrated costs—in our judgment fairly allocates between utility and customer the

[557] In contrast to the situation in Order No. 888, the *Cajun* court did not have before it a generic, Commission-imposed recovery mechanism for distinguishing stranded costs associated with the Commission's ordering of industry-wide open access from all uneconomic costs.

[558] *See AGD*, 824 F.2d at 1021.

[559] *Cf.* Eastman Kodak Company v. Image Technical Services, Inc., 504 U.S. at 486–87 (Scalia, J. dissenting) (''*Per se* rules of antitrust illegality are reserved for those situations where logic and experience show that the risk of injury to competition from the defendant's behavior is so pronounced that it is needless and wasteful to conduct the usual judicial inquiry into the balance between the behavior's procompetitive benefits and its anticompetitive costs.'').

[560] In effect, we recognize that we may have to endure some short-term delay in the transition from monopoly suppliers to competitive suppliers. However, this is not anticompetitive; it is a necessary part of a scheme that is procompetitive overall. *See American Gas Association* v. *FERC*, 888 F.2d 136, 149 (D.C. Cir. 1989) (''If conditioning access is a necessary part of a scheme that is procompetitive overall, however, then it does not violate the NGPA [Natural Gas Policy Act] even if it may seem to be anticompetitive when viewed in isolation.'').

[561] Eastman Kodak Company v. Image Technical Services, 504 U.S. 451, 461 (1992).

[562] A ''service'' can constitute a ''product'' for purposes of a tying analysis. *See Eastman Kodak Company* v. *Image Technical Services, Inc.*, 504 U.S. at 462.

[563] The Rule requires all transmission customers to purchase at least some reactive supply and voltage control service from the transmission provider. However, the Commission found that the cost of such services is ''part of the cost of basic transmission service.'' FERC Stats. & Regs. at 31,706; *mimeo* at 209. That is, it is a necessary part of providing the service and thus, by definition, not a ''tying.''

burdens and benefits of open access transmission.

Nor is it true that the Rule does not allow customers ''meaningful'' access to alternative power suppliers. The Final Rule pro forma tariff contains terms and conditions ensuring the provision of non-discriminatory transmission service. The requirements that a public utility take service under its own tariff for wholesale sales and purchases, adopt a non-discriminatory transmission information network, and separate power marketing and transmission functions further ensure non-discrimination and remove constraints to fair competition. The result is meaningful access to alternative suppliers that goes far beyond what was offered in the transmission tariff under review in *Cajun*.

Contrary to the claims of some, the Open Access Rule does not guarantee that a utility may sell its power at market-based rates. The open access compliance tariff required by Order No. 888 does mitigate transmission market power.[564] However, the Commission's Rule does not generically grant market-based rate authority to utilities that file compliance tariffs. Utilities must still demonstrate on a case-by-case basis that they not only have mitigated transmission market power but also do not have market power in generation[565] or other barriers to entry.

Notwithstanding the objections by some commenters that the stranded cost procedures of Order No. 888 fail to provide certainty in the computation of stranded cost charges, we believe that directly assigning stranded costs to departing generation customers using the revenues lost formula is the fairest and most efficient way to balance the competing interests of those involved. The alternatives that we considered (an up-front broad-based approach or an as-realized broad-based approach) have significant disadvantages and are extensively discussed in Order No. 888.[566] Following a careful evaluation of the alternatives, we concluded that a revenues lost formula to calculate a customer's stranded cost obligation is more reasonable and provides greater certainty than would other approaches, such as those that rely on broad-based surcharge schemes that impose costs that may never be incurred or those that result in widely fluctuating transmission rates.[567] As we stated in Order No. 888, while we recognize that some commenters oppose the revenues lost approach as imprecise, any ratemaking method that relies on estimates will be subject to forecasting error.[568] Nevertheless, we have gone to great lengths to provide specificity with respect to the calculation of the components of the formula.

In response to those commenters that argue that Order No. 888's stranded cost procedures will add costs of potential deal-killing magnitude to any power supply acquisition considered by a customer, we believe that, to the contrary, use of the formula will narrow the scope of disputes over the calculation of stranded costs, lend precision to the stranded cost amount it produces, and provide certainty to departing generation customers with respect to their stranded cost obligations.

APPA and ELCON object to the Commission's reference to *Western Resources* as a case affirming the Commission's ability to allow stranded cost recovery. Notwithstanding their efforts to distinguish *Western Resources* (for example, as a filed rate doctrine case, not a stranded cost case, and as a case involving no allegation of anticompetitive conduct), they have failed to make a convincing argument that our description of that case as ''confirm[ing] the validity of Commission-imposed stranded cost recovery mechanisms in the transition to competitive markets''[569] is not accurate. The case depends upon the validity of the Commission's decision to allow the recovery of costs stranded in the transition of the natural gas industry to a competitive market and supports the Commission's ability to allow stranded cost recovery in general. The same court, in *United Distribution Companies,* has recently confirmed the Commission's ability to allow the recovery of costs stranded in the transition to competitive markets, limiting its concerns to issues about ''how'' stranded costs should be recovered and from whom.[570]

3. Responsibility for Wholesale Stranded Costs (Whether To Adopt Direct Assignment to Departing Customers)

In Order No. 888, the Commission concluded that direct assignment of stranded costs to the departing wholesale generation customer through either an exit fee[571] or a surcharge on transmission is the appropriate method for recovery of such costs. We concluded that the departing generation customer (and not the remaining generation or transmission customers or shareholders) should bear the legitimate and prudent obligations that the utility undertook on that customer's behalf. In reaching this decision, we carefully weighed the arguments supporting direct assignment of stranded costs against those supporting the broad-based approach of spreading stranded costs to all transmission users of a utility's system. After a detailed review of the advantages and disadvantages of each approach, we concluded that, on balance, direct assignment is the preferable approach for both legal and policy reasons.[572] Our primary considerations were that direct assignment is consistent with the well-established principle that the one who has caused a cost to be incurred should pay that cost and that it will result in a more accurate determination of a utility's stranded costs than would an up-front, broad-based transmission surcharge.

The Commission also acknowledged that the direct assignment approach adopted in Order No. 888 is different from the approach taken for the natural

[564] Such tariff is a condition, but not the sole condition, for market-based rates. *See, e.g.,* Delmarva Power & Light Company, *et al.,* 76 FERC ¶ 61,331 (1996); *accord* Southern Company Services, Inc., 71 FERC ¶ 61,392 at 62,536 (1995); Heartland Energy Services, Inc., *et al.,* 68 FERC ¶ 61,223 at 62,059–60 (1994).

[565] A seller requesting market-based rates is not required to demonstrate any lack of generation market power with respect to sales from capacity for which construction commenced on or after the effective date (July 9, 1996) of the Rule. 18 CFR 35.27(a). However, if specific evidence is presented by an intervenor that a seller requesting market-based rates for sales from new generating capacity nevertheless has generation dominance, the Commission will evaluate whether the seller has generation dominance with respect to the new capacity. FERC Stats. & Regs. at 31,657; *mimeo* at 65–66.

[566] *See* FERC Stats. & Regs. at 31,797–800; *mimeo* at 477–85.

[567] Under the revenues lost approach, a customer's stranded cost obligation is calculated by subtracting the competitive market value of the power the customer would have purchased (on an average annual basis) from the average annual revenues that the customer would have paid had it remained on the utility's generation system, and multiplying the result by the period of time the utility reasonably could have expected to serve the customer beyond the contract termination but for the open access required under Order No. 888. *See* FERC Stats. & Regs. at 31,839–45 for a detailed explanation of the various components of the formula.

[568] FERC Stats. & Regs. at 31,841; *mimeo* at 600–01.

[569] FERC Stats. & Regs. at 31,793; *mimeo* at 464–65.

[570] 88 F.3d at 1129, 1182–83.

[571] We defined ''exit fee'' as the charge that will be payable by a departing generation customer upon the termination of its requirements contract with a utility (if the utility is able to demonstrate that it reasonably expected to continue serving the customer beyond the term of the contract), whether payable in a lump-sum payment or an amortization of a lump-sum payment. (The same charge also can be paid as a surcharge on the customer's transmission rate.)

[572] FERC Stats. & Regs. at 31,797–800; *mimeo* at 477–85.

gas industry. We explained why we believe that difference to be justified by pointing out a number of differences between the transition of the electric industry to an open transmission access, competitive industry and the transition of the natural gas industry to open access transportation service by interstate natural gas pipelines.[573] We also declined to require a utility seeking stranded cost recovery to shoulder a portion of its stranded costs on the basis that such a requirement would be a major deviation from the traditional principle that a utility should have a reasonable opportunity to recover its prudently incurred costs, and explained why we applied a different approach in the gas area.[574]

Rehearing Requests Opposing Full Recovery From Departing Customers

A number of entities submit that the Commission has not adequately explained its decision not to require some utility sharing of stranded costs when the utility can satisfy the reasonable expectation criteria. They object that the Commission did not meaningfully consider the arguments made by commenters concerning utility responsibility (such as poor management decisions) for stranded costs.[575]

ELCON argues that departing customers are not the sole cause of stranded costs. IL Industrials submits that the statement in the Rule that utility shareholders ''’had no responsibility for causing the legitimate, prudent and verifiable costs to be incurred’'' is untrue.[576] It argues that although utilities may have had a legal obligation to serve and meet projected demands, how the utility chose to meet those obligations was under the utility’s control. IL Industrials asserts that shareholders should bear some of the risk associated with the decisions of their management that were less than optimal. At a minimum, IL Industrials argues that the Commission should consider on a case-by-case basis (when it determines whether a utility has incurred legitimate and verifiable stranded costs) whether some amount of stranded costs should be shared with shareholders.

NASUCA challenges the Commission’s statement in Order No. 888 that requiring a utility to shoulder a portion of its stranded costs ''would be a major deviation from the traditional principle that a utility should have a reasonable opportunity to recover its prudently incurred costs.'' [577] It contends that there is no constitutionally guaranteed right of recovery of all prudent investment.[578] NASUCA further asserts that full recovery of uneconomic investment is not the norm. It submits that the Commission has rejected utility demands for full recovery of cancelled electric generation facilities.[579]

San Francisco cites *Market Street* as support for the proposition that the risk of unmarketability should fall, in whole or in part, on utility shareholders who knew of competitive risks and who have been compensated for those risks through rates of return.

A number of parties object that the Commission, in declining to require some shareholder sharing of stranded costs, is allowing the electric utility industry to claim more generous recoveries under Order No. 888 than it allowed the gas industry, and that it has provided no adequate rationale for this difference in treatment.[580] San Francisco states that although the Rule attempts to distinguish shareholder sharing in the natural gas industry ''as an extraordinary measure given the nature of the take-or-pay problem and the prevailing environment at that time,'' [581] the Commission has not identified how the nature of the take-or-pay problem was any more ''extraordinary'' than the nature of stranded costs in electric restructuring, or explain its reference to ''the prevailing environment at that time.''

Occidental Chemical submits that the Commission’s decision not to allocate a portion of stranded costs to utilities on cost causation grounds contradicts the Commission’s actions in Order No. 636, in which it required interruptible and new shippers, as beneficiaries of open access, to share in the costs of the transition.[582] Central Illinois Light states that the Commission should allow partial recovery of stranded costs and thereby correct key differences in the Commission’s responses to gas and electric transition costs.[583]

Occidental Chemical also objects that the Commission failed to address the merits of its suggestion that the Commission grant a utility a presumption of prudence in return for absorbing a percentage of its stranded costs.

ELCON, in a supplement to its rehearing request,[584] submits that the D.C. Circuit’s remand in *United Distribution Companies* of the aspect of Order No. 636 that allocated 100 percent of gas supply realignment costs to customers and none to pipelines has implications for the Commission’s decision in Order No. 888 to allocate 100 percent of stranded costs to departing customers without any shareholder sharing of the costs. ELCON suggests that although the D.C. Circuit indicated that a finding of threat to the financial viability of the pipeline sector might justify such allocation, there is no evidence in the record in the Order No. 888 proceeding, and the Commission has made no finding, that wholesale stranded cost recovery jeopardizes the financial viability of the utility sector. It

[573] FERC Stats. & Regs. at 31,800–802; *mimeo* at 485–90.

[574] FERC Stats. & Regs. at 31,802–03; *mimeo* at 490–92.

[575] *E.g.*, ELCON, IL Industrials, San Francisco, Nucor. Other entities that urge the Commission to require shareholders to shoulder a portion of the utility’s stranded costs include Central Illinois Light, AR Com, American Forest & Paper, Nucor, and Occidental Chemical. American Forest & Paper and Nucor suggest that full recovery destroys incentives to mitigate. Several entities also support spreading the costs to all of the utility’s customers. *E.g.*, American Forest & Paper, Central Illinois Light, AR Com.

[576] IL Industrials at 4–6 (citing Order No. 888, *mimeo* at 491–92).

[577] FERC Stats. & Regs. at 31,802; *mimeo* at 490.

[578] NASUCA cites in support of its position Covington & Lexington Turnpike Road Company v. Sandford, 164 U.S. 578 (1896); Market Street Railway Company v. Railroad Commission, 324 U.S. 548 (1945) (*Market Street*); Duquesne Light Company v. Barasch, 488 U.S. 299, 315–16 (1989).

[579] NASUCA cites in support of its position New England Power Company, 8 FERC ¶ 61,054 (1979), *aff’d sub nom.* NEPCO Municipal Rate Committee v. FERC, 668 F.2d 1327 (D.C. Cir. 1981), *cert. denied*, 457 U.S. 1117 (1982). NASUCA states that in that case, prudently incurred plant investment was abandoned because changing circumstances rendered the investment uneconomic; the Commission provided for a ten-year amortization of the plant investment, with no return on the unamortized balance. NASUCA says that this precedent demonstrates that the ''regulatory compact'' does not require full cost recovery.

[580] *E.g.*, Central Illinois Light, Occidental Chemical.

[581] FERC Stats. & Regs. at 31,802; *mimeo* at 491.

[582] Occidental Chemical argues that requiring gas customers to choose their suppliers during an open season enabled the pipelines to place a dollar value on their take-or-pay obligations. Shippers thus knew at the outset what their gas supply realignment (GSR) surcharge would be and could negotiate with other suppliers accordingly. Occidental Chemical says that most pipelines have already recouped their GSR costs and have made the transition to a competitive supply market in under three years. It argues that, on the other hand, allowing electric stranded costs to be recovered over an indefinite period will blunt the pro-competitive effect of Order No. 888.

[583] Central Illinois Light supports a recovery mechanism that would allow utilities to allocate stranded costs to requirements customers on a demand basis and to all transmission customers on a commodity basis. It argues that this would recognize the greater cost responsibility of requirements customers, recognize the benefits obtained by all transmission customers from open access, and reduce the charges to all customers to a more reasonable level.

[584] We will accept this pleading as a motion for reconsideration, not as a request for rehearing, because it was not filed within the 30-day statutory period for rehearing requests. *See* 16 U.S.C. § 825l(a).

adds that, to the extent the Commission relies on strict cost causation principles in Order No. 888, it is not clear how departing wholesale customers who signed contracts in 1985 could have ''caused'' utilities to incur uneconomic assets such as expensive nuclear facilities that were planned and ordered in the 1970s.

Commission Conclusion

As we explained in Order No. 888, we decided not to require a utility meeting the requirements for stranded cost recovery to shoulder a portion of its stranded costs because such a requirement would be a major deviation from the traditional principle that a utility should have a reasonable opportunity to recover its prudently incurred costs.[585] Our decision (which allows assignment of legitimate, prudent and verifiable stranded costs to departing requirements generation customers, not to shareholders or other customers of the utility) also follows the cost causation principle that has been fundamental to our regulation since 1935.[586] It is important, in this regard, to distinguish between assuring recovery of all uneconomic costs (which Order No. 888 does not do) and providing an opportunity for recovery where the evidentiary requirements of the Rule are met.

Allowing full recovery of stranded costs under Order No. 888 is not equivalent to allowing 100 percent recovery of the costs of all uneconomic assets. A utility may have uneconomic assets for a variety of reasons, including a decline in load, customer shifts to natural gas, customer energy conservation, loss of a large industrial customer, customer self-generation, and a customer gaining transmission access through another utility's transmission system. The Rule does not provide for the recovery of the costs of such uneconomic assets.

Instead, the Rule defines a discrete set of uneconomic costs that are stranded by FPA section 211 or Order No. 888 transmission service (when a customer uses the former supplying utility's transmission system to reach a new supplier) for which utilities may seek recovery. However, even as to this set of costs the Rule does not *guarantee* 100 percent recovery. To be eligible to recover such costs, a utility must satisfy the reasonable expectation test set forth in Order No. 888. Even then, the utility will be eligible to recover only costs that are legitimate, prudent and verifiable.

In response to those entities that argue that departing customers are not the sole cause of stranded costs and that poor management decisions may be partly to blame, we reiterate that a determination that a utility has a reasonable expectation of continuing to serve a customer would not, in all circumstances, mean that costs incurred by the utility were prudent. As we said in Order No. 888, we cannot make a blanket assumption that all claimed stranded costs were prudently incurred. We explained that prudence of costs, depending upon the facts in a specific case, may include different things, such as prudence in operation and maintenance of a plant, and the utility's ongoing obligation to exercise prudence in retaining existing investments and power purchase contracts and in entering into new ones.[587] We clarified, however, that we do not intend to relitigate the prudence of costs previously recovered.

Thus, to the extent that costs have not been previously recovered by a utility, and depending upon the facts presented, a customer from whom a utility is seeking to recover stranded costs may be able to challenge the prudence of those costs. If such prudence challenge is successful, then the utility would not be entitled to recovery of the imprudently incurred costs, through stranded cost recovery or otherwise. We believe that this fully addresses the concerns of those entities that contend that departing customers should not be responsible for costs that result from poor management decisions or other actions by the utility.[588]

As we explained in Order No. 888, our decision not to require utilities to shoulder a portion of their stranded costs is based on the traditional principle that a utility should have a reasonable opportunity to recover its prudently incurred costs.[589] NASUCA's reliance on the Commission's cancelled plant policy to support its argument that full recovery of uneconomic investment is not the norm is misplaced. The Commission's cancelled plant policy, which allows a utility to recover 50 percent of its prudently-incurred investment in a cancelled or abandoned plant, relates only to plants that are cancelled or abandoned prior to entering commercial service and thus prior to becoming used and useful.[590] The Commission has taken a different approach in the case of electric generating plants that are prematurely shut down after having been in commercial operation for a number of years. In the latter instance (which more closely resembles the type of costs for which a utility might seek recovery under Order No. 888 than does the cancelled plant before operation scenario), the Commission has allowed 100 percent recovery of prudently-incurred unamortized investment.[591]

585 FERC Stats. & Regs. at 31,802; *mimeo* at 490–91.

586 In response to ELCON's argument that it is not clear how departing wholesale customers who signed contracts in 1985 could have ''caused'' utilities to incur uneconomic assets such as expensive nuclear facilities that were planned and ordered in the 1970s, we note that customers taking requirements service generally pay an allocated share of total embedded costs, including the cost of investments made before the customer began service. This pricing principle is consistent with the method that Order No. 888 adopts for calculating a departing customer's stranded cost obligation. The revenues lost approach is not an asset-by-asset approach. Instead, it is an approach that looks at a utility's current rates, which are based on all the utility's assets, which may include both high cost and low cost generating facilities of various ages, and relies on the presumption that the fixed costs allocated to departing customers under their current rates are properly assignable to them. Thus, if a utility is able to demonstrate that it had a reasonable expectation of continuing to serve the customer after the contract term, the customer's stranded cost obligation would be computed based on the average annual revenues that the customer would have paid had it remained a customer of the utility; the calculation of stranded costs would not be tied to any particular investments that the utility made in a particular unit. As we explain in Section IV.J.9 below, the use of present annual revenues as the basis for the stranded cost calculation is based, among other things, on the presumption that present rates include all just and reasonable costs of providing service.

587 FERC Stats. & Regs. at 31,850; *mimeo* at 626.

588 Whether poor management decisions or other actions are imprudent would be decided on a case-by-case basis. *See, e.g.*, New England Power Company, Opinion No. 231, 31 FERC ¶ 61,047 at 61,081–84, *reh'g denied*, Opinion No. 231–A, 32 FERC ¶ 61,112 (1985), *aff'd sub nom.*, Violet v. FERC, 800 F.2d 280 (1st Cir. 1986); Minnesota Power & Light Company, Opinion No. 86, 11 FERC ¶ 61,312 at 61,644–45, *order on reh'g*, 12 FERC ¶ 61,264 (1980). However, a utility's costs are presumed prudent and a person challenging such costs would have the burden of going forward with evidence that raises a serious doubt as to prudence. *Id., 11 FERC at 61,645.*

589 *See, e.g.*, Maryland v. Louisiana, 451 U.S. 725, 748 (1981); Office of Consumers' Counsel v. FERC, 914 F.2d 290, 292 (D.C. Cir. 1990); City of New Orleans, Louisiana v. FERC, 67 F.3d 947, 954 (1st Cir. 1995).

590 See New England Power Company, Opinion No. 295, 42 FERC ¶ 61,016, *reh'g denied in part and granted in part*, Opinion No. 295–A, 43 FERC ¶ 61,285 (1988). We note that the Supreme Court case on which NASUCA relies to support its argument that there is no constitutionally guaranteed right of recovery of all prudent investment, *Duquesne*, also involved electrical generating facilities that were planned but never built. *See* 488 U.S. 299 (1989).

591 See Yankee Atomic Electric Company, Opinion No. 390, 67 FERC ¶ 61,318, (*Yankee Atomic*), *reh'g denied*, 68 FERC ¶ 61,364 (1994), *remanded on other grounds*, Town of Norwood, Massachusetts v. *FERC*, 80 F.3d 526 (D.C. Cir. 1996), offer of settlement accepted, letter dated January 30, 1997, Docket No. ER92–592–005. This case involved a nuclear plant that had been in operation for over 30 years. In affirming the Commission's decision to allow full recovery and not to apply Opinion No. 295's recovery rule for

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San Francisco's and NASUCA's reliance on *Market Street* is also distinguishable. That case involved an industry (street railway) that had been rendered economically obsolete by market forces. The electric industry today, in contrast, is clearly not obsolete. Moreover, the costs that Order No. 888 gives a utility an opportunity to recover even in the face of market forces would not become stranded but for statutory and regulatory changes.

A number of parties contend that the Commission has not provided an adequate rationale for its different treatment of shareholder sharing in the natural gas industry. ELCON also relies on the D.C. Circuit's remand in *United Distribution Companies* of Order No. 636's holding that pipelines could recover 100 percent of their gas supply realignment (GSR) costs. After further review of this matter in light of the Court's decision in *United Distribution Companies*, we reaffirm that, even though the Commission permitted pipelines to recover take-or-pay costs based on ''cost spreading'' and ''value of service'' principles, stranded electric utility costs should be recovered based on traditional cost causation principles. This is because, despite the fact that both sets of costs are incurred in connection with a transition to unbundled, open access service, there are also substantial differences between the circumstances surrounding the two industries' incurrence of their respective transition costs.

The pipelines' take-or-pay problems began before the Commission initiated open access transportation in Order No. 436. The severe gas shortages of the 1970s led to enactment of the Natural Gas Policy Act (NGPA), which initiated a phased decontrol of most new gas prices and established ceiling prices for controlled gas, including incentive prices for price-controlled new gas higher than the ceiling prices previously established by the Commission under the NGA.[592] To avoid future shortages, pipelines then entered into long-term take-or-pay contracts at the high prices made possible by the NGPA, and those high prices stimulated producers to greatly increase exploration and drilling.[593] When demand unexpectedly fell and supply increased, the pipelines found themselves contractually bound to take or pay for high-priced gas which they could not sell. Even before Order No. 436 issued in October 1985, pipeline take-or-pay exposure was approaching $10 billion.[594] In 1986, as pipelines were just beginning to implement open access transportation under Order No. 436 and before the August 1987 issuance of Order No. 500, the pipelines' outstanding unresolved take-or-pay liabilities peaked at $10.7 billion.[595]

The Commission and the industry had never previously faced a take-or-pay problem of this nature or magnitude. In earlier times, pipelines had made take-or-pay payments to particular producers, and the Commission had a policy of permitting such payments to be included in rate base and then recovered as a gas cost when the pipeline later took the gas under make-up provisions in the contract.[596] By 1983, however, the pipelines could not manage their take-or-pay problems, and stopped honoring the bulk of their take-or-pay liabilities.[597] They then sought settlements with the producers to reform or terminate the uneconomic take-or-pay contracts and to resolve outstanding take-or-pay liabilities. Because pipelines had never previously incurred significant take-or-pay settlement costs, the Commission had no policy concerning whether and how pipelines were to recover those costs. The Commission commenced establishing such a policy in an April 1985 policy statement,[598] just six months before Order No. 436. When Order No. 500 issued, few take-or-pay settlement costs had yet been included in pipelines' rates. However, since the pipelines' outstanding take-or-pay liabilities were in the neighborhood of $10 billion, it was clear that pipelines would incur massive costs in their settlements with producers.

In short, when the Commission first addressed the issue of how to allocate take-or-pay settlement costs in Order No. 500, it did so under the shadow of the pipelines' vast outstanding take-or-pay exposure. The essential problem, therefore, was to decide which customers' rates should be raised to reflect the billions of dollars of take-or-pay settlement costs that the pipelines were incurring, but that the pipelines had still not filed to recover. To have allocated those costs solely to any one segment of the industry would have imposed a crushing new burden on that segment. For example, if the Commission had allocated the take-or-pay settlement costs entirely to bundled sales customers who chose to convert to transportation-only service, those customers would have ended up far worse off than if they remained as bundled sales customers.

As a result of all these facts, the fundamental premise of Order No. 500 was, as the Court expressed it in *KN Energy*, that ''the extraordinary nature of this problem requires the aid of the entire industry to solve it.'' [599] In order to accomplish this result, Order No. 500 established an equitable sharing mechanism for pipelines to use in recovering their take-or-pay settlement costs as an alternative to recovery through their commodity sales rates. Relying on ''cost spreading'' and ''value of service'' principles, the Commission permitted pipelines to allocate their take-or-pay settlement costs among all the pipelines' customers. The Commission also required the pipelines using the equitable sharing mechanism to absorb a portion of the costs in return for the ability to recover an equal portion through a fixed charge. Importantly, pipelines using the equitable sharing mechanism and agreeing to absorb a portion of the costs were given a presumption that their take-or-pay settlement costs were prudent. Those who did not choose to avail themselves of the sharing/absorption mechanism could still file for recovery of take-or-pay costs pursuant to the traditional ratemaking methodology. Because the pipelines' cash flow problems were so severe and they could not reasonably expect to recover their costs through their sales

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plants abandoned before operation, the court explained:

Although ratepayers generally 'bear the expense of depreciation' and although investors generally 'are entitled to recoup from consumers the full amount of their investment in depreciable assets devoted to public service,' [citations omitted] Opinion No. 295 makes a logical exception to this full recovery rule for plants abandoned before operation; in such cases, ratepayers have not benefitted from the plant. The situation here is quite different. Because customers have benefitted from the operation of the plant for over 30 years, and because ceasing plant operations will benefit customers by lowering rates, such an exception is unwarranted. Moreover, applying Opinion No. 295's recovery rule would not, as it would in the case of a plant that never began operations, promote economic efficiency.'' 80 F.3d at 532.

In *Yankee Atomic*, the Commission also allowed recovery of 100 percent of construction work in progress and of post-shutdown O&M expenditures.

[592] Order No. 500–H, Regulations Preambles 1986–1990, FERC Stats. & Regs. ¶ 30,867 at 31,509 (1989).

[593] *Id.* at 31,509–10.

[594] *Id.* at 31,513.

[595] *Id.*

[596] Regulatory Treatment of Payments Made in Lieu of Take-or-Pay Obligations, Regulations Preambles 1982–85, FERC Stats. & Regs. ¶ 30,637 at 31,301 (1985).

[597] In Order No. 500–H, the Commission found that, although pipelines incurred total take-or-pay exposure over the period January 1, 1983 through June 30, 1987 of over $24 billion, they made take-or-pay payments totalling only $.7 billion. Order No. 500–H, Regulations Preambles 1986–1990 ¶ 30,867 at 31,514.

[598] Regulatory Treatment of Payments Made in Lieu of Take-or-Pay Obligations, Regulations Preambles 1982–85, FERC Stats. & Regs. ¶ 30,637 (1985).

[599] 968 F.2d 1295, 1301 (D.C. Cir. 1992).

rates, they readily availed themselves of the special mechanism, with its presumption of prudence, rather than the more protracted traditional ratemaking option.[600]

The Court in *KN Energy* upheld the Commission's use of cost spreading in connection with the allocation of take-or-pay costs among a pipeline's open access customers.[601] The Court held that ''the ratemaking rationales of Order No. 500 can be reconciled with the NGA, given the unusual circumstances surrounding the take-or-pay problem, and the limited nature—both in time and scope—of the Commission's departure from the cost-causation principle.'' [602] The Court emphasized that ''[w]e hold only—and quite narrowly—that in the context of Order No. 500 the Commission has not betrayed its obligations to the NGA or precedent by employing these ratemaking principles in its attempt to bring closure to the take-or-pay drama.'' [603]

The unusual circumstances that justified the departure from cost causation principles in Order Nos. 500/528 are not present in the electric industry. In Order No. 888's discussion of the Commission's decision not to order any generic abrogation of existing requirements and transmission contracts between electric utilities and their customers, we have already pointed out:

> At the time the Commission addressed this situation in the natural gas industry, it was faced with shrinking natural gas markets, statutory escalations in natural gas prices under the Natural Gas Policy Act, and increased production of gas. In other words, there was a market failure in the industry. * * * In contrast, there is no such market failure in the electric industry.[604]

The electric utility costs potentially stranded by Order No. 888 are fixed costs arising from the utility's electric generation business, including, for example, depreciation expense associated with the utilities' own generation facilities and a return on the original cost of its investment in those facilities. They also include costs associated with mandatory QF purchase contracts. Unlike take-or-pay settlement costs, these costs are not an extraordinary expense that the Commission has never previously encountered. Rather, the stranded electric costs that are subject to the direct assignment provisions of Order No. 888 are ordinary costs that have always been, and are currently, included in the utility's rates for electric generation approved by the Commission. And there is no pre-existing industry-wide market failure. Thus, we are not confronted at the start of the electric open access program with a vast outstanding cost not currently reflected in the electric utilities' rates, as we were at the start of the natural gas open access program.

Therefore, unlike the situation with the natural gas industry, stranded electric utility costs can be allocated among customers based upon traditional cost causation principles without imposing inequitable and unreasonable burdens on particular customer classes. Direct assignment to departing requirements generation customers through the stranded cost recovery mechanism contained in the Rule is consistent with the traditional cost causation principle because it recognizes the link between the incurrence of stranded costs and the decision of a particular generation customer to use open access transmission on the utility's system to leave the utility's generation system and shop for power, and bases the utility's ability to recover stranded costs on its ability to demonstrate that it incurred costs with the reasonable expectation that the customer would remain on its generation system beyond the term of the contract. The stranded costs are measured as the difference between revenues the utility would have recovered from the customer and the market value of the utility's power.

In essence, therefore, all that the direct assignment provisions of Order No. 888 require is that certain customers (those whom a utility is able to demonstrate it reasonably expected to continue serving beyond the contract term) who convert to transmission-only service continue, for a period, to bear certain generation costs that they were previously bearing. This helps to minimize immediate cost shifts to the remaining generation customers, and is thus consistent with the Court's concerns in *AGD* about cost shifts due to open access transportation.[605] At the same time, it does not impose any crushing new burden on the converting generation customers, as would have happened if in the natural gas industry the Commission had allocated the take-or-pay settlement costs entirely to pipeline sales customers who converted to transportation-only service.

On the issue of utility absorption of stranded costs, as ELCON points out, the D.C. Circuit in *United Distribution Companies* remanded Order No. 636 to the Commission for further explanation as to why the Commission had exempted pipelines from sharing in Order No. 636 GSR costs in light of: (1) Its reliance on ''cost spreading'' and ''value of service'' principles in allocating GSR costs among the pipelines' customers, and (2) the absorption requirement in Order Nos. 500/528. As the Court explained:

> If the Commission intends to assign GSR costs according to these 'cost spreading' and 'value of service' principles, it must do so consistently or explain the rationale for proceeding in another manner. We approved the invocation of those principles in *KN Energy* because FERC had concluded that the take-or-pay crisis could be resolved only by spreading costs throughout the '*entire industry*' 968 F.2d at 1301 (emphasis added), and because we recognized that '*all segments of the industry*' * * * will benefit, *id*. (emphasis added), from restructuring.[606]

For the reasons discussed above and in Order No. 888, we have chosen to use traditional cost causation principles both in allocating stranded electric costs to certain electric utility customers and in finding that the utilities should be given an opportunity for full recovery of certain legitimate, prudent, and verifiable stranded costs. Thus, Order No. 888 does not present the issue of whether the Commission inconsistently applied ratemaking principles to the recovery of stranded costs that was of concern to the court in *United Distribution Companies* when it remanded the analogous portion of Order No. 636.

Moreover, based on the facts summarized above, the Commission concludes that the rationale we used to support the Order Nos. 500/528 absorption requirement is not valid for electric utility costs stranded by Order No. 888. Order No. 528–A, where the Commission gave its fullest justification for that absorption requirement, did not rely on either the ''cost spreading'' or ''value of service'' rationales to support the absorption requirement.[607] Order Nos. 500/528 consistently recognized that the Commission must ''provide a pipeline a reasonable opportunity to

[600] By contrast, Order No. 888 does not provide a presumption of prudence for utilities' stranded cost recovery proposals. Once again, the more traditional concept that the utility must prove costs were prudently incurred will apply.

[601] The Court did not review the Order No. 500/528 requirement that pipelines absorb a share of the take-or-pay costs. *See* AGA v. FERC, 888 F.2d 136, 152 (D.C. Cir. 1989), and AGA v. FERC, 912 F.2d 1496, 1519 (D.C. Cir. 1990), *cert. denied*, 498 U.S. 1084 (1991), both holding the absorption requirement not ripe for review.

[602] *KN Energy*, 968 F.2d at 1301.

[603] *Id.* at 1302.

[604] FERC Stats. & Regs. at 31,664; *mimeo* at 84.

[605] *See, e.g., AGD*, 824 F.2d at 1026.

[606] *United Distribution Companies*, 88 F.3d at 1189.

[607] Order No. 528–A, 54 FERC ¶ 61,095 at 61,303–05 (1991).

recover its prudently incurred costs.'' [608] However, Order No. 528–A reasoned that, because the take-or-pay problem was caused more by general market conditions than by any regulatory action of the Commission, it was appropriate to require the pipelines to share in the losses arising from those market conditions as a condition to using the alternative recovery mechanism.[609]

In these circumstances, the Commission concludes that it would not be reasonable to require electric utilities to bear costs that, unlike the Order Nos. 500/528 take-or-pay costs, arise as the direct result of Congress' and the Commission's change in the regulatory regime through FPA section 211 and Order No. 888. This is particularly the case since the electric utilities' potential stranded costs relate to large capital expenditures or long-term contractual commitments (some mandated by federal law) to buy power made many years ago in reliance on the preexisting regulatory regime.

Moreover, in a separate order, the Commission is responding to the *United Distribution Companies* remand by reaffirming the policy established in Order No. 636 that pipelines should be permitted full recovery of their prudently incurred GSR costs. In that order, the Commission finds that the rationale Order No. 528–A used to support the Order Nos. 500/528 absorption requirement is inapplicable to GSR costs. The remand order explains that, in the face of extraordinary market conditions, Order Nos. 500/528 adopted extraordinary measures. However, as we are finding here with respect to stranded electric utility costs, the remand order holds that the extraordinary market circumstances that gave rise to the requirement for pipeline absorption of gas supply costs in Order Nos. 500/528 were not present at the time of Order No. 636. Even before the Commission initiated open access transportation in Order No. 436, the market was preventing pipelines from recovering costs incurred under their take-or-pay contracts. The Order Nos. 500/528 absorption requirement reflected the preexisting effect of the market, which would have required absorption even without open access transportation under Order No. 436. The remand order finds that, contrary to the situation when Order No. 436 issued, at the time of Order No. 636, pipelines were generally able to take gas under their few remaining high-priced take-or-pay contracts from the late 1970s and early 1980s and were no longer accumulating significant additional take-or-pay obligations. This was because the pipelines were still performing a significant sales service and had reformed most of their uneconomic take-or-pay contracts.[610]

The remand order accordingly holds that the Commission's regulatory actions in Order No. 636 have caused the pipelines to incur the GSR costs. This is particularly the case because Order No. 636 required the pipelines to unbundle their natural gas and transportation sales and forbade the pipelines from making sales unless they were made by a separate sales or marketing entity. Order No. 888 also requires generation or commodity sales to be unbundled from sales of transmission. In these circumstances, traditional ratemaking principles require the Commission to allow the pipelines an opportunity to recover the full amount of the expenses caused by its actions. Thus, the Commission's approach to Order No. 636 GSR costs is similar to its approach in Order No. 888 to stranded electric generation costs.

Rehearing Requests Citing Other Inconsistencies Between Commission Treatments of the Gas and Electric Industries

VT DPS and Valero submit that Order No. 888 does not satisfactorily distinguish the Commission's rejection of gas pipelines' attempts to impose exit fees on departing customers. They argue that the Commission opposed the imposition of such exit fees in the gas context as anticompetitive because it would force customers desiring to switch suppliers when their contracts expired to pay the supply costs of both the new and former suppliers.

VT DPS and Valero take issue with the Commission's attempt to distinguish a recent *El Paso* case [611] as a ''post-restructuring'' case under Order No. 636. They contend that the Commission consistently applied the same policy (rejection of gas pipeline attempts to impose exit fees) before restructuring under Order No. 636. They further claim that the Commission cannot articulate a plausible basis for permitting utilities with notice provisions to file for exit fees, having denied El Paso's proposal outright without giving it an opportunity to rebut the presumption.

VT DPS and Valero also state that the ''stranded'' costs for which the Commission allowed recovery under Order No. 636 were costs that would be rendered unrecoverable because the costs would not be incurred to provide transportation service and because there would be no wholesale load from which to recover the costs. They indicate that the Commission has held that such gas costs are stranded only if rendered unrecoverable as a direct result of the restructuring required under Order No. 636. They submit that when a utility loses wholesale load or a municipality establishes a new distribution system and the utility cannot resell the capacity left unused, the utility's costs are not necessarily ''stranded''—*i.e.*, rendered unrecoverable—any more than if the utility's load declines because of conservation, an economic downturn or an increase in self-generation. They argue that the Commission should limit utility stranded cost claims solely to those cases where the utility can demonstrate that its costs have been rendered unrecoverable as a direct result of the Rule.

Commission Conclusion

We explained in Order No. 888 why we disagree with the argument that the Commission cannot impose an exit fee to recover stranded costs because the Commission did not allow gas pipelines to do so. We noted that the Rule establishes procedures for providing a potential departing generation customer advance notice (*before* it leaves its existing supplier) of the stranded cost charge (whether it is to be paid as an exit fee or a transmission surcharge) that will be applied if the customer decides to buy power elsewhere and the Commission decides the utility has satisfied the stranded cost recovery criteria of the Rule, *e.g.*, the reasonable expectation criterion. We indicated that in the natural gas context, in contrast, the Commission has prohibited

[608] Order No. 500–H, Regulations Preambles 1986–1990, FERC Stats. & Regs. at 31,575. Those orders permitted all pipelines to seek full recovery of their take-or-pay settlement costs through their sales commodity rates. The Commission required pipelines to absorb a share of their Order No. 500/528 take-or-pay costs only if they chose to use the alternative, equitable sharing recovery mechanism.

[609] Order No. 528–A, 54 FERC at 61,303–05.

[610] A number of entities (*e.g.*, VT DPS, Valero, Occidental Chemical) challenge the Commission's suggestion that, after Order No. 436, many of the former bundled sales customers of the pipeline had departed. To the extent that Order No. 888 suggested that many pipelines' sales customers had terminated their sales service before Order No. 636 issued, we note that, as the Commission indicated in Order No. 636, pipeline sales constituted less than 20 percent of total annual throughput on major pipelines. FERC Stats. & Regs. ¶30,939 at 30,400. However, the Commission also found that in 1991 over 60 percent of peak day capacity on major pipelines that made bundled sales was reserved for pipeline firm sales service. *Id.* at 30,399. Thus, we clarify that although on an annual basis customers were buying most of their gas from other suppliers, pipelines were making significant sales of gas, particularly on peak days.

[611] El Paso Natural Gas Company, 72 FERC ¶61,083 (1995) (*El Paso*).

pipelines from developing and charging an ''exit fee'' *after* a customer had implemented its gas purchase decision, noting that otherwise, the customer would not know in advance the full cost consequences of its nomination decision.[612]

We continue to believe that the Commission's decisions concerning natural gas pipeline exit fees, relied on by VT DPS and Valero, are not inconsistent with Order No. 888's limited approval of exit fees for the recovery of certain stranded electric utility costs. VT DPS and Valero point first to two cases decided by the Commission in 1988 and 1989 involving Gas Inventory Charges (GICs) proposed by Transwestern Pipeline Company (Transwestern)[613] and El Paso Natural Gas Company (El Paso)[614] pursuant to our Order No. 500 policy statement. However, those cases are not relevant here, essentially because the exit fees at issue in those cases were not designed to recover costs arising from the transition to open access transportation, unlike the stranded electric utility costs at issue here.

In the *Transwestern* case cited by VT DPS and Valero, Transwestern included in its proposal to implement a GIC a request for permission to assess an exit fee. The exit fee would have been charged to its largest local distribution company customer if that customer initially chose to nominate purchases under the GIC but then subsequently reduced its nominations. The Commission found the proposed exit fee inconsistent with both (1) its policy that GIC customers know in advance the full cost consequences of their nomination decisions and (2) its objective that prices under the GIC be constrained by market forces.

However, this holding was not applicable to Transwestern's recovery of costs incurred as part of its transition to open access transportation, since the Commission did not intend the GIC as a vehicle for recovery of such transition costs. The GIC was intended solely as a forward-looking charge that would recover costs the pipeline would incur in the future under its reformed, market responsive gas supply contracts.[615] The Commission's intent was that, before implementing GICs, pipelines would negotiate settlements of their existing uneconomic take-or-pay contracts and file to recover the resulting settlement costs under the Order No. 500 equitable sharing mechanism.[616] Indeed, in the *Transwestern* order cited by VT DPS and Valero, the Commission suggested that Transwestern postpone implementation of its GIC until it had renegotiated its supply contracts and filed to recover the resulting costs under the Order No. 500 equitable sharing mechanism.[617]

That mechanism included a fixed take-or-pay charge analogous to the direct assignment provisions of Order No. 888. The Commission permitted pipelines to allocate to sales customers who converted from sales to transportation the same fixed take-or-pay charge that those customers would have been allocated had they not converted.[618] Moreover, in a later order involving Transwestern's recovery of take-or-pay settlement costs under its Order No. 500 equitable sharing mechanism, the Commission expressly held:

> In appropriate circumstances, the Commission may approve exit fees for departing customers, either through a condition on the abandonment of the purchase obligation of customers subject to the Commission's jurisdiction or through tariff language giving appropriate notice of such a fee before the departure.[619]]

As discussed in the preceding section of this order, the direct assignment provisions of Order No. 888, in essence, require that certain electric generation customers who convert to transmission-only service continue, for a period, to bear certain generation costs that they were previously bearing. That requirement is similar to the Commission's requirement, in connection with its Order No. 500 program, that pipeline sales customers who convert to transportation-only service continue to pay the same Order No. 500 fixed take-or-pay charge as they would have paid had they not converted.

VT DPS and Valero also claim that permitting electric utilities to recover stranded generation costs through exit fees to customers converting to transmission-only service is inconsistent with our 1995 order in *El Paso*,[620] rejecting that pipeline's exit fee proposal. We see no inconsistency. El Paso proposed, several years after its restructuring pursuant to Order No. 636, to impose an exit fee on its firm *transportation* customers who terminated or reduced their firm transportation service. The fee was designed to require the departing firm transportation customer to continue to pay a portion of El Paso's fixed transmission costs for a period of time after the customer's departure. The fee bore no relationship to El Paso's pre-restructuring merchant function, since it was designed to recover El Paso's costs of performing open access transportation service after its restructuring.

In both Order No. 888 and this order, we are acting consistently with *El Paso*. Similar to our refusal in *El Paso* to permit a pipeline to impose an exit fee on customers departing its transportation system altogether (whether for all or a portion of their firm service), so also here we are refusing to permit electric utilities to recover stranded costs from customers who depart their transmission systems altogether. We believe that, in that situation, there is no direct nexus between the customer's departure (and the stranding of costs) and Commission-required transmission access, since the customer is not using its former supplier's open access tariff to reach an alternative power supplier.

Order No. 888 thus permits an exit fee only to electric generation customers who, although they stop purchasing power from the utility, become transmission-only customers of the former supplying utility.[621] By contrast,

[612] FERC Stats. & Regs. at 31,802; *mimeo* at 489.

[613] Transwestern Pipeline Company, 44 FERC ¶ 61,164 at 61,536 (1988) (*Transwestern*).

[614] El Paso Natural Gas Company, 47 FERC ¶ 61,108 at 61,314, *reh'g denied*, 48 FERC ¶ 61,202 (1989).

[615] Order No. 500, Regulations Preambles (1986–1990), FERC Stats. & Regs. ¶30,761 at 30,793–94 (1987).

[616] *CPUC* v. *FERC*, 988 F.2d 154, 168 (D.C. Cir. 1993), quoting, Transwestern Pipeline Company, 55 FERC ¶61,157 at 61,509 (1991).

[617] *Transwestern*, 44 FERC at 61,536. The 1989 El Paso order cited by VT DPS and Valero (47 FERC ¶61,108) reiterated the policy established in *Transwestern* concerning exit fees in the context of GICs. The El Paso order is distinguishable from our approach to exit fees in Order No. 888 for the same reasons as *Transwestern*.

[618] Natural Gas Pipe Line Company, 46 FERC ¶ 61,335 at 62,013 (''Consistent with the court's holding in AGD, that Part 284 transportation and CD conversion must be accompanied by take-or-pay relief, the Commission finds that a pipeline's sales customers who convert to transportation must continue to be liable for the take-or-pay costs allocated to them without regard to the fact that they are no longer sales customers but only transportation customers.''), *reh'g denied*, 47 FERC ¶61,247 (1989); Transwestern Pipeline Company, 65 FERC ¶61,060 at 61,473 (1993), *reh'g denied*, 66 FERC ¶61,287 at 61,827–828 (1994), *aff'd sub nom. Western Resources, Inc.* v. *FERC*, 72 F.3d 147 (D.C. Cir. 1996).

[619] Transwestern Pipeline Company, 64 FERC ¶61,145 at 62,166 (1993), *reh'g denied*, 66 FERC ¶61,287 (1994). However, as illustrated by the situation described in the cited Transwestern order, some sales customers had departed altogether from the systems of their historical pipeline suppliers before the Commission recognized the need for continued allocation of Order No. 500 take-or-pay costs to those customers. In these circumstances, the filed rate doctrine prevented such continued allocation.

[620] 72 FERC ¶61,083 (1995).

[621] In Order Nos. 636–A and 636–B, the Commission not only rejected exit fees where the

Continued

El Paso proposed an exit fee to transmission customers terminating their transmission service. In short, the exit fee we have found acceptable in Order No. 888 is related to the electric utility's pre-restructuring generation service, unlike El Paso's rejected exit fee, which bore no relationship to El Paso's pre-restructuring merchant service.[622]

Finally, VT DPS's and Valero's comments concerning the Commission's treatment of Order No. 636 "stranded costs" attempt to make distinctions that do not make a difference for purposes of the Commission's treatment of Order No. 888 stranded costs. We have explained above that the electric industry's transition to an open transmission access, competitive industry is different in a number of respects from the natural gas industry's transition to open access transportation service by interstate natural gas pipelines. We also have explained why a different approach to recovery of legitimate, prudent and verifiable stranded costs in the electric industry is justified. On this basis, the Commission's definition and treatment of "stranded" costs under Order No. 636 need not dictate our definition and treatment of stranded costs under Order No. 888. In any event, in response to VT DPS's and Valero's request that the Commission limit utility stranded cost claims solely to those cases where the utility can demonstrate that its costs have been rendered unrecoverable as a direct result of the Rule,[623] we note that Order No. 888 does require a causal nexus between the availability and use of Commission-required transmission access and the stranding of costs.

Rehearing Requests Opposing Recovery of Stranded Costs in Transmission Rates

VT DPS and Valero submit that although the Commission has not proposed to depart from cost-based ratemaking methodologies in establishing transmission rates, Order No. 888 contravenes cost causation principles by recovering generating costs in transmission rates.[624] They argue that although the court in *KN Energy* held that the Commission might depart from strict cost-causation principles to permit pipelines to recover gas supply costs from transportation customers in extraordinary circumstances, the "extraordinary circumstances" were that the pipelines had no remaining sales customers and thus were left with no vehicle for recovering gas supply costs. On this basis, the court approved a mechanism under which gas supply costs were spread over virtually all transmission users. They describe as incongruous the Commission's claim in Order No. 888 that permitting direct assignment of stranded power costs in a transmission rate is a cost-based approach.

VT DPS and Valero further argue that even if the Commission were inclined to justify stranded cost recovery from departing customers on non-cost grounds, the Commission cannot show that the circumstances justifying similar cost recovery from gas pipeline transportation customers exist at the wholesale level in the electric industry because: (1) unlike its approach to gas pipelines, the Commission has not proposed to allow existing wholesale electric customers to get out of their contracts early; (2) there is no industry-wide problem; wholesale sales account for only a small fraction of the total business of regulated electric utilities, while gas pipelines had virtually all wholesale sales; and (3) direct assignment of generating costs only to departing customers is the antithesis of the cost-spreading rationale that provided the justification for the limited departure from cost-causation principles permitted in *KN Energy*. They contend that, in any event, the Commission cannot spread costs broadly even if they are recovered from all transmission customers because the largest users are retail customers that would be exempt from wholesale stranded cost surcharges.

A number of other entities also oppose the recovery of stranded generation costs in transmission rates.[625] Some of them contend that section 212(a) of the FPA limits the transmitting utility to the recovery of transmission-related costs.[626] PA Munis contends that the plain language of section 212, as amended by EPAct, limits the rates that can be charged under a section 211 order to those "'which permit the recovery by such utility of all the costs incurred in connection with the transmission services and necessary associated services * * *'"[627] PA Munis contends that Congress would not have limited recovery to the costs incurred in connection with the transmission services and necessary associated services if it had intended to allow the transmission rates to include part of a utility's costs for unused generation facilities completely unrelated to the cost of the transmission facilities.[628] PA Munis asserts that the legislative history of EPAct supports its position that there is no authorization for the Commission to include unused generation costs as part of the transmission costs that are allocable to transmission under section 212.[629]

customer left the system altogether, but also found exit fees unnecessary for the recovery of GSR costs in the circumstance in which a bundled sales customer converts to transportation-only service. *See* Order No. 636–B, 61 FERC ¶ 61,272 at 62,041 (1992). Exit fees were unnecessary in the latter circumstance because under the Commission's method of allocating GSR costs to all firm transportation customers based on their contract demands, a former bundled sales customer would pay the same GSR costs after terminating its sales service (through the volumetric surcharge on transportation) as it would if it had remained as a sales customer.

[622] As we explained in Order No. 888, the Commission did not treat a notice of termination provision in El Paso's contract as a conclusive presumption that El Paso had no reasonable expectation of continuing to serve certain customers, as VT DPS and Valero contend. FERC Stats. & Regs. at 31,802, note 639; *mimeo* at 489, note 639. Instead, the July 1995 *El Paso* order acknowledged that the April 1995 Supplemental Stranded Cost NOPR had proposed that the existence of a notice of termination provision in a contract be treated as a "rebuttable" presumption of no reasonable expectation. On that basis, the Commission suggested in *dicta* that "*[e]ven if* the rules proposed in [the Supplemental Stranded Cost] NOPR were applied here [*which they were not*], El Paso would have difficulty justifying" its exit fee proposal under the NOPR's reasonable expectation standard given the existence of a notice of termination provision in the contract. 72 FERC at 61,441 (emphasis added).

[623] Under their proposal, it appears that costs would be "unrecoverable" only if there were no wholesale load from which to recover the costs. This would result in shifting costs to customers that had no responsibility for causing them to be incurred or for causing them to be stranded. In Order No. 888, we rejected such an approach as fundamentally unfair and as inconsistent with the well-established principle of cost causation.

[624] In support of this argument, they cite CPUC v. FERC, 894 F.2d 1372, 1380–81 (D.C. Cir. 1990) as standing for the proposition that, in a cost-based transmission rate, there is no logical basis for including gas-supply related expenses or savings in the rates for customers who take only transmission service. *See also* American Forest & Paper (no justification for including excess generation costs in transmission rates).

[625] *E.g.*, TX Com, APPA, IN Consumer Counselor, IN Consumers, PA Munis, AR Com, MO/KS Coms.

[626] *E.g.*, APPA, PA Munis, IN Consumer Counselor, IN Consumers.

[627] PA Munis at 28. PA Munis also argues that the last sentence of section 212(a) makes it clear that the "rates, charges * * * for transmission services provided pursuant to an order under section 211 shall ensure that to the extent practicable, *costs incurred in providing the wholesale transmission services, and properly allocable to the provision of such services are recovered* * * *.' " (emphasis added by PA Munis).

[628] *See also* IN Consumers, IN Consumer Counselor.

[629] PA Munis cites in support the following excerpt from House Report No. 102–474, Part I: This section [211] also provides that FERC shall permit the transmitting utility to recover all prudent costs *incurred in connection with providing transmission services,* plus a reasonable return on investment, including an appropriate share of the costs of any enlargement of transmission facilities necessary to provide such service. H.R. Rep. No. 102–474, Part I, 102d Cong., 2d Sess. 194 (1992), *reprinted in* 1992 U.S.C.C.A.N. 1959, 2017 (emphasis supplied by PA Munis).

AR Com and MO/KS Coms argue that the FPA does not allow the Commission to include costs in a transmission rate that are not caused by the provision of transmission service.[630] MO/KS Coms contend that retail stranded costs are largely generation costs that were not caused by any request to use transmission service or by any actual transmission usage, and are not an opportunity cost of providing transmission service. Citing the language in section 212 of the FPA allowing the transmitting utility to recover ''all costs incurred in connection with the transmission services and necessary associated services,'' AR Com contends that nowhere does the Energy Policy Act or any other relevant statute authorize the collection of retail, non-transmission costs through transmission rates.

Commission Conclusion

We disagree with VT DPS's and Valero's argument that Order No. 888 contravenes cost causation principles by recovering generating costs in transmission rates. As the court in *United Distribution Companies* stated: '' 'Cost causation' correlates costs with those customers for whom a service is rendered or a cost is incurred.'' [631] Whether stranded costs are recovered through a surcharge on the transmission rates of a departing generation customer, or through an exit fee, the point is that under Order No. 888 they are recovered from the customer that caused them to be incurred. The only distinction is the mechanism by which they are recovered from that customer.

The Commission is not aware of any prohibition on permitting recovery through a transmission rate of what has traditionally been recovered through the generation component of a rate, so long as the utility does not double recover and the customer does not pay more than the costs that it caused to be incurred.[632] Indeed, the Commission has been upheld in permitting opportunity costs (foregone economic savings) to be charged as a transmission rate when they are higher than a traditional embedded cost transmission rate.[633] There is no significant difference between an ''opportunity cost'' component of a transmission rate and a stranded cost charge imposed through transmission rates. Both concern the recovery of generation costs. To be sure, in the former case these generation costs are incurred by reason of using high cost generation instead of substituting lower cost generation, and in the latter case the costs are ''incurred'' by reason of the loss of a customer.[634] But, for purposes of cost recovery, these are distinctions without a difference. In both situations, the transmission rate is used to recover something other than the capital, operating, and maintenance costs of facilities used to provide the transmission service at issue. If the Commission were without authority to provide for cost recovery of these other types of costs in transmission rates, the court would not have affirmed the volumetric surcharge on transportation in *KN Energy,* nor would it have affirmed the opportunity cost charge in *Penelec.*

As we note above, we are *not* proposing a departure from strict cost-causation principles such as that allowed in *KN Energy,* where the pipeline was allowed to recover 50 percent of its take-or-pay settlement costs through a volumetric surcharge on all transportation customers, including those that had never purchased gas from the pipeline.[635] Because we disagree with VT DPS's and Valero's position that recovery of stranded costs through a surcharge on transmission constitutes recovery on non-cost grounds,[636] we will reject their requests for rehearing on this issue.[637]

We also reject the argument that section 212 of the FPA prohibits the recovery of stranded generation costs in transmission rates. There is nothing on the face of the statute or in its legislative history to support this position. In fact, section 212(a) permits recovery of ''legitimate, verifiable and economic costs'' of providing transmission service. Stranded costs clearly are an economic cost of providing transmission when the stranding results from the ordered transmission service. By definition, the costs for which this Rule provides an opportunity for recovery would not have been stranded *but for* Commission-mandated transmission access. Stranded costs under this Rule are the costs that a utility incurred to provide service to a customer based on a reasonable expectation that the utility would continue to serve the customer beyond the term of their contract, and that become stranded when the customer uses Commission-mandated

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[630] They cite in support of this proposition Farmers Union Central Exchange, Inc. v. FERC, 734 F.2d 1486 (D.C. Cir.), *cert. denied,* Williams Pipe Line Company v. Farmers Union Central Exchange, Inc., 469 U.S. 1034 (1984).

[631] 88 F.3d at 1188–89.

[632] Additionally, we note that a stranded cost surcharge to transmission is merely a vehicle for collecting the exit fee. The surcharge would be in effect only until the stranded cost obligation is met. It is not a component of the transmission rate in the sense that a transmission customer who uses a very large amount of transmission while the rate is in effect would pay more than its stranded cost obligation.

[633] *See* Pennsylvania Electric Company v. FERC, 11 F.3d 207 (D.C. Cir. 1993) (*Penelec*). As the Commission explained, opportunity costs are the actual costs that a utility incurs by providing transmission service to a customer instead of using the transmission itself to reduce its generation costs on behalf of its native load (*i.e.,* the foregone economy energy transfers). Pennsylvania Electric Company, 60 FERC ¶61,034 at 61,120, 61,126 (1992), *aff'd, Penelec,* 11 F.3d 207.

[634] Technically, the costs in the latter situation were previously incurred as a result of investment by the utility on behalf of the departing customer. However, the costs are ''incurred'' in the sense of becoming stranded when the customer leaves the utility's system. In both situations, recovery of the costs is permitted through transmission rates in order to keep the utility (and its other customers) from unfairly suffering economic losses as a result of providing transmission to others.

[635] Moreover, we note that, in addressing the natural gas industry's transition costs, the Commission did rely on traditional cost causation principles in approving pipeline proposals to allocate fixed take-or-pay charges to sales customers converting to transportation-only service. *See* Transwestern Pipeline Company, 65 FERC ¶61,060 at 61,473 (1993), *reh'g denied,* 66 FERC ¶61,287 at 61,825–28 (1994). The Commission found that the pipelines entered into their take-or-pay contracts to serve their sales customers. The conversion of those customers to open access transportation required pipelines to enter into settlements with producers to shed gas supplies. Therefore, there was a causal connection between the customer's conversion and the pipeline's incurrence of the take-or-pay settlement costs. Here, there is a similar causal connection between the stranding of generation investment made on behalf of a wholesale customer and that customer's decision to use Commission-mandated open access transmission to reach a new supplier.

[636] The case on which VT DPS and Valero rely, CPUC v. FERC, involved the disposition of a pipeline's production-related deferred tax reserve when the switch to NGPA pricing mooted application of tax normalization (which sought to match the timing of a customer's contribution toward a cost with enjoyment of any offsetting tax benefit). The Commission's decision not to credit the deferred tax reserve to current users of the pipeline's transmission service was based, among other things, on a determination that the deferred tax fund was completely unrelated to the pipeline's transmission service. *See* 894 F.2d at 1378–80. In contrast, as discussed below, the costs for which this Rule provides an opportunity for recovery would not have been stranded *but for* Commission-mandated transmission access.

[637] We also reject AR Com's argument that the *Farmers Union* case prohibits the Commission from allowing the recovery of non-transmission costs in a transmission rate in the limited circumstances proposed in Order No. 888. The issues before the court in that case are distinguishable from the recovery of stranded generation costs in transmission rates. *Farmer's Union* involved the court's review of a Commission order establishing maximum rate ceilings to be applied to oil pipelines in which the Commission invoked non-cost factors (the need to stimulate additional oil pipeline capacity) as one reason for setting high maximum rates. The use of non-cost factors was itself not at issue. Rather, the court found that the Commission had ''failed to specify in any detail how 'non-cost' factors, such as the need to stimulate additional pipeline capacity, might justify its decision to set maximum rates at such high levels.'' 734 F.2d at 1501. In Order No. 888, in contrast, the Commission has fully explained the basis for giving utilities an opportunity to recover stranded costs from departing customers through a surcharge to the customers' transmission rates.

transmission access to reach a new generation supplier. In this respect, stranded costs, like opportunity costs,[638] are not costs associated with the actual facilities used to provide transmission service. Rather, they are an ''economic cost'' of providing the transmission service at issue.

4. Recovery of Stranded Costs Associated With New Wholesale Requirements Contracts

In Order No. 888, we concluded that future wholesale requirements contracts should explicitly address the mutual obligations of the seller and buyer, including the seller's obligation to continue to serve the buyer, if any, and the buyer's obligation, if any, if it changes suppliers. This means that utilities must address potential stranded cost issues when negotiating new contracts or be held strictly accountable for the failure to do so.

We stated that we will allow recovery of wholesale stranded costs associated with any new requirements contract (executed after July 11, 1994, or extended or renegotiated to be effective after July 11, 1994) only if explicit stranded cost provisions are contained in the contract. We defined ''explicit stranded cost provision'' (for contracts executed after July 11, 1994) as a provision that identifies the specific amount of stranded cost liability of the customer(s) and a specific method for calculating the stranded cost charge or rate. However, for purposes of requirements contracts executed after July 11, 1994 but before May 10, 1996 (the date on which Order No. 888 was published in the Federal Register), we clarified that a provision that specifically reserved the right to seek stranded cost recovery consistent with what the Commission permits in the Final Rule (without identifying the specific amount of stranded cost liability of the customer(s) and calculation method) nevertheless will be deemed an ''explicit stranded cost provision.'' On the other hand, a provision in a requirements contract executed after July 11, 1994 but before May 10, 1996 that merely postpones the issue of stranded cost recovery without specifically providing for such recovery will *not* be considered an ''explicit stranded cost provision.'' We said that, after May 10, 1996, a provision must identify the specific amount of stranded cost liability of the customer(s) and a specific method for calculating the stranded cost charge or rate in order to constitute an ''explicit stranded cost provision.'' [639]

We also concluded that a requirements contract that is extended or renegotiated for an effective date after July 11, 1994 becomes a ''new'' requirements contract for which stranded cost recovery will be allowed only if explicitly provided for in the contract.

We decided not to impose a regulatory obligation on wholesale requirements suppliers to continue to serve the power needs of their existing requirements customers beyond the end of the contract term. The only exception to this would be if the customer decides to remain a requirements customer for the period for which the Commission finds that the supplying utility reasonably expected to continue serving the customer. In such a case, the supplying utility will be obligated to offer continuing service to the requirements customer for the period the utility reasonably expected to continue serving the customer.

We also decided to no longer require prior notice of termination under section 35.15 for any power sales contract executed on or after July 9, 1996 (the effective date of the Final Rule pro forma tariff) that is to *terminate by its own terms* (such as on the contract's expiration date), but to require written notification of the termination of such contract within 30 days after termination takes place. We said that we will continue to require prior notice of the proposed termination of any power sales contract executed before July 9, 1996 (even if the contract is to terminate by its own terms) as well as any unexecuted power sales contract that was filed before that date.

Further, we decided to retain the section 35.15 filing requirement for all transmission contracts because the Commission must be assured that transmission owners are not exerting market power in negotiating or terminating transmission contracts. This filing requirement will provide the customer an opportunity to notify the Commission if the termination terms are disputed or if the customer was not given adequate opportunity to exercise its limited right of first refusal under the Final Rule (*see* Section IV.A.5).[640]

Requests for Rehearing

Utilities For Improved Transition asks the Commission either to clarify that it will enforce stranded cost provisions as agreed to by the parties and accepted for filing by the Commission (presumably even if they do not meet the definition of ''explicit stranded cost provision'' contained in the Preamble [641]), or to modify the definition contained in the Preamble (and add the term to the list of definitions in section 35.26(b)) to give contracting parties the option of specifying either a specific amount of stranded cost liability *or* a formula for calculating the stranded cost charge or rate. Utilities For Improved Transition contends that, particularly in the case of long-term contracts, the parties may not be able to quantify what the stranded cost liability will be at the time they enter into a contract.

Several entities assert that if the Commission is to permit recovery for stranded costs, it should include a symmetrical mechanism to permit customers with below-market rates or net undervalued assets a means to continue to receive power at below-market rates if the customer had a reasonable expectation of continued service.[642] OH Consumers' Counsel objects that the only exception in Order No. 888 to the Commission's decision not to impose a regulatory obligation on a utility to continue to serve existing requirements customers beyond the end of the contract ''would be if the customer decides to remain a requirements customer for the period for which the Commission finds that the *supplying utility reasonably expected* to continue serving the customer.'' [643] According to OH Consumers' Counsel, this language nullifies the *customer's* reasonable expectation of continuation of service under its existing contractual arrangement.

TDU Systems similarly says that the Commission has not explained why the suppliers' expectations are to be honored, but the customers' expectations are not. TDU Systems objects that the Commission failed to explain why it rejected allowing requirements customers to demonstrate a reasonable expectation that they would continue to be able to obtain supplies of power at rates based on embedded cost after the expiration of

[638] *See* note 633 *supra.*

[639] *See* Orange and Rockland Utilities, Inc., 76 FERC ¶ 61,037 (1996).

[640] FERC Stats. & Regs. at 31,804–06; *mimeo* at 497–501.

[641] FERC Stats. & Regs. at 31,805; *mimeo* at 497.

[642] *E.g.*, TDU Systems, OH Consumers' Counsel. TDU Systems proposes that the Commission give a requirements customer the choice of extending its existing contract at existing rates for a period corresponding to the customer's expectation of continued service or receiving a payment from the utility consisting of the difference between what the customer must pay for new supplies and what it paid under the contract. TDU Systems describes the latter option as a ''benefits lost'' approach modeled after the ''revenues lost'' approach of Order No. 888.

[643] FERC Stats. & Regs. at 31,805; *mimeo* at 498 (emphasis added by OH Consumers' Counsel).

their supply contracts. TDU Systems submits that the case for providing extra-contractual relief to wholesale purchasers is more compelling than the case for providing extra-contractual relief to wholesale suppliers. It argues that it is likely that some cooperatives and municipal utilities would not survive the drastic impact to their businesses that the elimination of cost-based rates could bring.

OH Consumers' Counsel submits that the filing of a section 206 complaint by customers of utilities with rates below market does not provide adequate protection or symmetry for the customers. It contends that a section 206 case is an inadequate remedy because: (1) the utility holds all of the necessary information for analyzing such a case, but the procedure shifts the burden of proof from the utility to the customer; and (2) it provides only delayed relief for parties who could be irreparably harmed by the imposition of the market-based rates.

TDU Systems argues that eliminating the prior notice of termination requirement in section 35.15 for post-July 9, 1996 wholesale requirements contracts will result in discrimination and monopolization. It contends that the Commission closes its eyes to the fact that termination of a requirements contract can affect 100 percent of a customer's power supply, while it is likely to affect less than 10 percent of a large public utility's load. It submits that eliminating the prior notice of termination requirement is tantamount to finding that termination of all such contracts by their terms will be just and reasonable, but that no such finding can presently be supported. TDU Systems maintains that there remains significant market power in the markets in which transmission dependent utilities, especially small transmission dependent utilities, operate. It recommends that the Commission use section 35.15 to require that wholesale contracts not be terminated unless such termination is just and reasonable.

PA Munis objects that the Commission did not specifically address in Order No. 888 its proposal that contracts approved after July 11, 1994 (but executed before that date) be treated as new contracts. It submits that under the Commission's reasoning in setting the July 11, 1994 cut-off date, utilities that executed requirements contracts after that date had no reasonable expectation that they would be permitted to recover costs by seeking to amend the contract. It argues that the same reasoning applies where the contract was executed but not approved or accepted by the Commission by the July 11, 1994 notice date.

Commission Conclusion

We will clarify the definition of ''explicit stranded cost provision'' for requirements contracts executed after July 11, 1994. As long as the contracting parties are in agreement, a provision in a post-July 11, 1994 requirements contract will be considered an ''explicit stranded cost provision'' if it identifies *either* the specific amount of stranded cost liability of the customer *or* a specific method for calculating the stranded cost charge or rate.

We will reject the arguments of TDU Systems and OH Consumers' Counsel that ''symmetry'' requires that the Commission provide a generic mechanism in this Rule to allow existing requirements customers with below-market rates a means to continue to receive power beyond the contract term at the pre-existing contract rate if the customer had a reasonable expectation of continued service. Unlike the generic findings we have made with respect to extra-contractual recovery of stranded costs associated with requirements contracts executed on or before July 11, 1994, we do not have a sufficient basis on which to make generic findings that customers under such contracts may be entitled to extend a contract *at the existing rate*. Utilities' expectations may have resulted in millions of dollars of investments on behalf of certain customers and the possibility of shifting the costs of those investments to other customers that did not cause the costs to be incurred. In the case of customers' expectations, however, even if customers generally expected to stay on a supplier's system beyond the contract term, it is not likely that most customers could have expected to continue service *at the existing rate* unless specified in the contract. Moreover, the consequences of customers' expectations as a general matter would not have the potential to shift significant costs to other customers.

Nevertheless, our conclusion that we cannot make generic findings or provide a generic formula for addressing this issue does not mean that a customer under a contract may not exercise its procedural rights under section 206 to show that the contract should be extended at the existing contract rate,[644] or to make such a showing in the context of a utility's proposed termination of a contract pursuant to the section 35.15 notice of termination (approval) requirement, which we have retained for power supply contracts executed prior to July 9, 1996 (the effective date of the Rule).

We believe that while the relationship between utilities and their wholesale requirements customers may have given rise to an inference or expectation on the part of the wholesale requirements customer that the contract would continue beyond the stated term, it is not clear to what extent a customer could demonstrate a reasonable expectation that such continued service would be *at the existing contract rate* (which may be below the market price). This is particularly the case for contracts in which the utility has not waived its unilateral right to make section 205 filings to change the rates. Even in contracts where rates were fixed for the contract term, however, if the utility were to agree to extend such a contract for a new term, the rates under that contract would not necessarily have remained the same. On this basis, a customer may be able to demonstrate that it had a reasonable expectation of continued service beyond the contract term, but not necessarily at the same rate level. It is for this reason that we believe this issue must be addressed on a case-by-case basis and that this Rule is not the proper mechanism for granting the relief sought by TDU Systems and OH Consumers Counsel.

Nevertheless, we do not intend to prejudge whether a requirements customer could ever make a showing that it reasonably expected service beyond the contract term at the existing contract price. Nor do we intend to preclude a customer from attempting to make such a showing in appropriate circumstances.

We also believe that we adequately addressed in Order No. 888 TDU Systems' argument that elimination of the prior notice of termination requirement in section 35.15 for post-July 9, 1996, wholesale requirements contracts will result in discrimination and monopolization. As we stated in Order No. 888, we believe that the concerns of TDU Systems can be fully addressed without retaining the section

[644] If the customer under a contract has not waived its rights to seek changes to the contract, it may exercise its procedural rights under section 206 to show that failure to extend the contract at the existing contract rate would not be just and reasonable. If the customer has waived its rights to challenge the contract (*i.e.*, it is bound by a *Mobile-Sierra* standard), it may exercise its rights under section 206 to show that it would be contrary to the public interest not to extend the contract at the existing rate. Although OH Consumers' Counsel objects that a section 206 proceeding is an inadequate remedy because it places the burden of proof on the customer, we believe that it is appropriate that the customer, as the complainant in such a case, bear the burden of proof.

35.15 prior notice of termination requirement for post-July 9, 1996 contracts. While we have agreed to provide for extra-contractual stranded cost recovery as a *transition* matter, it is our objective that, prospectively, parties should address their mutual expectations clearly through contract terms that explicitly address the mutual obligations of the seller and buyer at contract expiration. This would include the seller's obligation to continue to serve the buyer after contract expiration, if any. If the customer believes that termination of its contract at the end of the term would not be just and reasonable (or, in the case of a *Mobile-Sierra* contract, would not be in the public interest), it can file a complaint with the Commission under section 206 of the FPA.

We will reject PA Munis' request that contracts approved after July 11, 1994 (but executed before that date) be treated as ''new'' contracts for purposes of stranded cost recovery because modifying the notice date at this point in the proceeding would work an inequitable result. Beginning with the initial stranded cost NOPR, the Commission put entities on notice that contracts ''executed'' on or before July 11, 1994 would constitute ''existing'' contracts. Although a utility arguably could have amended such an existing contract to include an explicit stranded cost provision prior to its (post-July 11, 1994) approval by the Commission, the NOPR did not require the utility to do so. As a result, it would be unfair for the Commission to change the cut-off terms now.

5. Recovery of Stranded Costs Associated With Existing Wholesale Requirements Contracts

In Order No. 888,[645] the Commission concluded that it would permit utilities the opportunity to seek recovery of legitimate, prudent and verifiable stranded costs for ''existing'' wholesale requirements contracts (executed on or before July 11, 1994) that do not already contain exit fees or other explicit stranded cost provisions.[646] We explained why we believe that July 11, 1994—the date on which the initial Stranded Cost NOPR was published and, thus, on which the industry was put on notice of the proposal to disallow prospectively extra-contractual recovery of stranded costs—is the appropriate date for distinguishing ''existing'' requirements contracts from ''new'' requirements contracts.

We noted our desire that utilities attempt to renegotiate with their customers existing requirements contracts that do not contain exit fees or other explicit stranded cost provisions. If a contract is not renegotiated to add such a provision, we explained that, before the expiration of the contract: (1) A public utility or its customer may file a proposed stranded cost amendment to the contract under sections 205 or 206; or (2) a public utility in a section 205 proceeding, or a transmitting utility in a section 211 proceeding, may file a proposal to recover stranded costs associated with any such existing contract through its transmission rates for a customer that uses the utility's transmission system to reach another generation supplier.

We also concluded that, even if an existing requirements contract contains an explicit *Mobile-Sierra*[647] provision, it is in the public interest to permit the public utility to seek a unilateral amendment to add stranded cost provisions if the contract does not already contain exit fees or other explicit stranded cost provisions.[648] We explained why our determination that it is in the public interest to give public utilities a limited opportunity to propose contract changes unilaterally to address stranded costs if their contracts do not already explicitly do so satisfies the public interest standard of the *Mobile-Sierra* doctrine. We also indicated that customers with *Mobile-Sierra* contracts that do not explicitly address stranded costs may file complaints under section 206 of the FPA to propose to address stranded costs in existing requirements contracts.

We concluded that a public utility or its customer should be allowed to file a proposed stranded cost amendment, or a public utility or transmitting utility should be allowed to file a proposal to recover stranded costs through a departing generation customer's transmission rates, at any time prior to the expiration of the contract.

Rehearing Requests—July 11, 1994 Cut-Off Date

Utilities For Improved Transition, repeating an argument raised in previous comments in this proceeding, objects to the Commission's July 11, 1994 cut-off date for distinguishing between ''existing'' and ''new'' requirements contracts. It argues that stranded cost recovery should be assured for all contracts executed before the effective date of the Rule (*i.e.,* July 9, 1996), not just those executed before July 11, 1994. It asserts that parties to contracts executed after July 11, 1994 but before July 9, 1996 should have the same opportunity as parties to pre-July 11, 1994 contracts to offer evidence as to their reasonable expectations. Utilities For Improved Transition asserts that agencies may not promulgate retroactive rules without express statutory authority,[649] and that the FPA does not give the Commission such statutory authority.

Puget raises a somewhat different point. It notes that the definition of a ''new'' requirements contract as ''any wholesale requirements contract * * * *extended or renegotiated to be effective after July 11, 1994*'' (emphasis added) was not proposed until March 29, 1995 (in the supplemental stranded cost NOPR). Puget states that the initial stranded cost NOPR proposed to give a utility three years from the date of Federal Register publication of the final stranded cost rule to negotiate or to file for stranded cost recovery. According to Puget, the March 1995 supplemental stranded cost NOPR proposed a retroactive change by defining a contract executed prior to July 11, 1994 but extended or renegotiated to be effective after that date as a ''new'' contract and by removing the three-year window for negotiating stranded cost recovery. By this change, Puget argues that the extension of a contract between the date of Federal Register publication of the initial NOPR (July 11, 1994) and the issuance of the supplemental NOPR (March 29, 1995) may have converted it into a ''new'' rather than an ''existing''

[645] FERC Stats. & Regs. at 31,809–814; *mimeo* at 510–24.

[646] We explained that if an existing requirements contract includes an explicit provision for payment of stranded costs or an exit fee, we will assume that the parties intended the contract to cover the contingency of the buyer leaving the system, and we will reject a stranded cost amendment to such a contract unless the contract permits renegotiation of the existing stranded cost provision or the parties to the contract mutually agree to a new stranded cost provision. Similarly, we said that we will reject a stranded cost amendment to an existing requirements contract if the contract prohibits stranded cost recovery (or precludes recovery for termination or reduction of service) or prohibits renegotiation of an existing stranded cost or exit fee provision, unless the parties to the contract mutually agree to a new stranded cost provision.

[647] *See* United Gas Pipeline Company v. Mobile Gas Service Corporation, 350 U.S. 332 (1956); FPC v. Sierra Pacific Power Company, 350 U.S. 348 (1956).

[648] As a complement to our finding that, notwithstanding a *Mobile-Sierra* clause in an existing requirements contract, it is in the public interest to permit amendments to add stranded cost provisions to such contracts if the public utility proposing the amendment can meet the evidentiary requirements of this Rule, we concluded that customers under *Mobile-Sierra* contracts ought to have the opportunity to demonstrate that their contracts no longer are just and reasonable.

[649] Citing Motion Picture Association of America v. Oman, 969 F.2d 1154 (1992); *Bowen* v. *Georgetown University Hospital,* 488 U.S. 204 (1988).

contract for stranded cost recovery purposes. Puget asks the Commission to revise the definition of ''existing wholesale requirements contract'' in Order No. 888 and 18 CFR 35.26 to include contracts executed on or before July 11, 1994 that were extended prior to the issuance of the supplemental stranded cost NOPR (March 29, 1995) and for which stranded cost provisions were filed with the Commission prior to issuance of Order No. 888. Puget submits that failure to do so would be arbitrary and capricious and would deprive utilities with such contracts of adequate notice of a proposed rule.[650]

Commission Conclusion

We will reject Utilities For Improved Transition's rehearing request because we believe that we adequately explained in Order No. 888 why adoption of the July 11, 1994 cut-off date is appropriate and does not constitute retroactive rulemaking. We said in Order No. 888 that because all parties were put on notice in the initial stranded cost NOPR that July 11, 1994 would be the operable date for the ''existing''/''new'' contract distinction, utilities that executed requirements contracts after that date could have had no reasonable expectation that they would be permitted to recover any costs extra-contractually. Moreover, we explained that because the costs at issue are extra-contractual costs, the Commission's notice to all parties that contracts executed after July 11, 1994 (the date that the initial NOPR was published in the Federal Register) will be enforced by their terms as far as stranded cost recovery is concerned does not constitute ''retroactive rulemaking.'' The Commission has merely put all parties on notice that the opportunity for extra-contractual stranded cost recovery would not be available for any requirements contracts executed after July 11, 1994.

The July 11, 1994 date is appropriate because it is the date on which all interested parties were given notice in the Federal Register that the recoverability of stranded costs for contracts executed on or before that date that did not provide for such recovery was at issue. The parties to requirements contracts executed after July 11, 1994 have been free to provide for stranded cost recovery in the contract, or not. The point is that, for requirements contracts executed after the cut-off date, stranded cost recovery will be governed solely by the terms of the contract.

We believe that Puget has raised a valid point concerning the potential impact of the Commission's decision in the March 29, 1995 supplemental stranded cost NOPR to treat extensions or renegotiations of existing contracts as ''new'' contracts for stranded cost purposes on parties that extended or renegotiated an existing contract prior to March 29, 1995. However, we expect that the situation described by Puget may be an isolated instance. On this basis, we do not believe it necessary to modify the definition of ''existing wholesale requirements contracts'' in Order No. 888 and 18 CFR 35.26 as requested by Puget. Nevertheless, we clarify that we will consider on a case-by-case basis whether to waive the provisions of 18 CFR 35.26 and to treat a contract extended or renegotiated (without adding a stranded cost provision) to be effective after July 11, 1994 but before March 29, 1995 as an existing contract for stranded cost purposes.[651]

Rehearing Requests—Mobile-Sierra

Several entities challenge the Commission's generic *Mobile-Sierra* public interest finding. According to APPA, the Commission cannot make the public interest determination in a generic rulemaking, whether for stranded cost or non-stranded cost modifications.

A number of entities object that the Commission does not identify any utilities whose existence is jeopardized without full wholesale stranded cost recovery.[652] PA Munis and APPA assert that vague allegations of harm if utilities do not recover stranded costs do not satisfy the public interest standard which they view to be ''practically insurmountable.''[653] American Forest & Paper contends that there is not one fact to support the Commission's assumption about threats to the financial stability of the electric utility industry. ELCON submits that significant retail stranded cost exposure does not justify the rule on wholesale stranded cost recovery.

VT DPS and Valero submit that the Commission has not explained how allowing utilities to abrogate their contracts to extract exit fees from former customers vindicates any public interest. They argue that even assuming that wholesale customers depart en mass, the customers can only do so as their contracts expire; thus, the exodus, if it occurs, will be a trickle, not a flood. VT DPS and Valero maintain that even if some utilities were put at risk, it would not justify a generic rule. They contend that based on *AGD* v. *FERC*,[654] a generic solution is not proper for a problem existing only in ''isolated pockets.''

PA Munis submits that, even assuming that the financial integrity of some utilities may be threatened, the missing link in the Commission's logic for a generic rule is that there is no protection for customers having *Mobile-Sierra* contracts with public utilities that are not faced with financial problems or cost shifting to third parties as a result of the open access requirements. PA Munis asserts that, at a minimum, each utility having *Mobile-Sierra* contracts should be required to show on an individual basis that the public interest standard has been satisfied.

American Forest & Paper argues that Order No. 888 is not made even-handed by allowing requirements customers to also challenge fixed-rate, fixed-term contracts. It submits that letting a customer file to amend a contract only as long as that amendment also addresses stranded costs is a ''heads you win, tails I lose'' proposition for the customer.

APPA and TDU Systems request clarification of the scope of the Commission's decision to allow a utility ''to seek modification of contracts that may be beneficial to the customer'' if the customer is permitted to argue for modification of existing contracts that are less-favorable to it than other generation alternatives. APPA expresses concern that this language could be interpreted to mean that once a

[650] Puget notes that it executed a letter agreement with the Port of Seattle on January 12, 1995 to continue in place the terms of an existing contract until February 2, 1996, or the execution of a new agreement, whichever was earlier. It says that the parties were working within the context of the initial stranded cost NOPR, which would have given Puget three years from the date of the publication of the final rule to negotiate or file for stranded cost recovery. However, based on the definition of ''new'' contract in the Supplemental NOPR, the extension of the Puget/Port of Seattle contract may have converted it into a ''new'' rather than an ''existing'' contract for stranded cost recovery purposes. Puget states that it filed an amendment to the contract on December 28, 1995, that included stranded cost recovery provisions. Those provisions are pending in Docket Nos. ER96–714–000 and ER96–697–000. On January 10, 1997, the presiding judge issued an Initial Decision in Docket No. ER96–714–001 finding that Puget, by executing the January 1995 letter agreement, had not waived its eligibility to recover stranded costs. *See* Puget Sound Power & Light Company, 78 FERC ¶ 63,001 (1997).

[651] As discussed in note 650, *supra,* the presiding judge in Docket No. ER96–714–001 recently issued an Initial Decision finding that Puget did not waive its eligibility to recover stranded costs when it entered into a January 1995 letter agreement with the Port of Seattle extending the term of the parties' 25-year sales contract for up to one year to accommodate further negotiations. Puget Sound Power & Light Company, 78 FERC ¶ 63,001 (1997).

[652] *See, e.g.,* ELCON, PA Munis, APPA.

[653] *See also* ELCON.

[654] 824 F.2d at 1019.

customer seeks modification of stranded cost provisions in an existing contract, the utility may be able to challenge its entire contract with the customer. If this means the utility can modify contract provisions unrelated to stranded costs, APPA submits that the Commission has failed to address the *Mobile-Sierra* public interest issues associated with modifying non-stranded cost provisions in an existing contract. If not, APPA contends that the Commission should clarify the language. APPA objects that the Commission has not placed any limits on the types of modifications that a selling utility can make, nor specified the types of changes that it thinks a utility will likely make. It states that the Commission needs to explain why joint modification by both the seller and the purchaser can meet the public interest standard. According to APPA, the Commission has not explained the need for symmetrical treatment of contracts negotiated at a time when the Commission has found that the supplying public utilities were exercising their monopoly over transmission facilities in an unduly discriminatory manner.

APPA also contends that the Commission's reliance on *Northeast Utilities* [655] is misplaced because that case involved the Commission's review of a newly-filed contract, as opposed to subsequent review of a contract previously accepted and approved by the Commission. APPA further asserts that *Northeast Utilities* involved an affiliate transaction, whereas this rulemaking is targeted at arm's-length agreements between unrelated selling and purchasing utilities. According to APPA, this rulemaking does not present any of the concerns at issue in an affiliate transaction, and the Commission should have applied the ''practically insurmountable'' public interest standard doctrine from *Papago,* the classic ''low-rate'' case.

Commission Conclusion

We disagree with those entities that argue that the Commission cannot make the public interest determination in a generic rulemaking. It is well established that it is within the Commission's discretion to decide whether we act through rule or through case-by-case adjudications.[656] As we explained in Order No. 888, we believe it is appropriate that our public interest finding be made on a generic basis given the fact that, by this Rule, we are requiring full open access that could significantly affect historical relationships among traditional utilities and their customers and the ability of utilities to recover prudently incurred costs.

At the same time, however, we are not eliminating the need for case-by-case demonstrations that stranded cost recovery should be allowed. Our public interest finding is that utilities be permitted to *seek* extra-contractual recovery of stranded costs in certain defined circumstances and that they be allowed to recover stranded costs *only* if they make a case-specific demonstration.

Our holding applies only to wholesale requirements contracts (with *Mobile-Sierra* clauses) executed on or before July 11, 1994 that do not contain an exit fee or other explicit stranded cost provision. We will not permit modification of any contract that addresses the stranded cost issue explicitly, unless the contract specifically permits such modifications. Instead, we are examining requirements contracts that do not clearly address the issue in the context of the traditional regulatory regime under which they were signed—a regulatory environment in which it was assumed as a matter of course that the great majority of requirements customers would stay with their original suppliers and that these suppliers had a concomitant obligation to plan to supply these customers' continuing needs.

Further, utilities with *Mobile-Sierra* contracts that seek recovery of stranded costs will have the burden, on a case-by-case basis, of showing they had a reasonable expectation of continuing to serve the departing generation customer. Although we have decided on a generic basis that it is in the public interest to permit public utilities with *Mobile-Sierra* contracts to make unilateral filings, we are not automatically approving any amendment that a particular utility might file. If a public utility unilaterally files a proposed stranded cost amendment under either section 205 or 206 of the FPA, this does not necessarily mean that the Commission will find it appropriate to allow such amendment. In addition, customers with *Mobile-Sierra* contracts that do not explicitly address stranded costs may also file complaints under section 206 of the FPA to propose to address stranded costs in existing requirements contracts. The Commission will analyze any proposed stranded cost amendment to a *Mobile-Sierra* contract, whether proposed by the utility or by its customer, based on the particular circumstances surrounding that contract. Thus, the case-by-case findings that some commenters seek will, in effect, be made when the Commission determines whether to approve a proposed stranded cost amendment to a particular contract.[657]

Although several entities have raised various challenges to the sufficiency of the Commission's public interest finding, we believe that we have satisfied the public interest standard by showing how third parties may ultimately bear the burden if public utilities with *Mobile-Sierra* contracts are not given any opportunity to propose contract changes to address stranded costs.[658] As we explained in Order No. 888, if the Commission fails to give a public utility this opportunity, and the utility's financial ability to continue the provision of safe and reliable service is impaired, third parties (customers relying on the public utility for their electric service) will be placed at risk. Similarly, if the Commission fails to give a public utility the opportunity to directly assign costs to the customers on whose behalf they were incurred, and some of the utility's customers leave the utility's generation system for that of another supplier without paying such costs, third parties (the utility's remaining customers) may be harmed by having to bear costs that were not incurred to serve them and that are stranded by the other customers' departures via open access transmission. We believe that protective action in the public interest is particularly necessary where, as here, a utility's rates could become insufficient because of fundamental changes in the industry that largely result from legislative or regulatory changes that could not be anticipated.

In response to those entities that contend that speculation of financial jeopardy or generalized statements of what may occur without reference to particular public utilities is not sufficient to satisfy the public interest standard, we disagree. The Commission need not make findings about particular utilities because the Rule does not

[655] Northeast Utilities Service Company v. FERC, 55 F.3d 686 (1st Cir. 1995) (*Northeast Utilities*).

[656] *See* Order No. 888, FERC Stats. & Regs. at 31,679; *mimeo* at 127–28.

[657] Because the Commission's public interest finding only applies to utilities that would seek to amend their contracts to add stranded cost provisions (not to those that face no stranded cost exposure and thus no need to amend their contracts to add stranded cost provisions), we reject as misplaced PA Munis' claim that there is no protection for customers having *Mobile-Sierra* contracts with public utilities that are not faced with financial problems or cost shifting to third parties as a result of the open access requirements.

[658] As noted above, this finding applies only to wholesale requirements contracts with *Mobile-Sierra* clauses if the contracts were executed on or before July 11, 1994 and do not contain an exit fee or other explicit stranded cost provision.

award stranded costs—it simply sets out generic criteria for determining recovery in a particular case. If a utility does not meet the criteria, there will be no stranded cost recovery. The public interest determination rests on the obvious conclusion that the failure of a utility to recover costs prudently incurred and financed based on investor expectation of traditional cost recovery clearly adds regulatory risk that investors reasonably did not expect.

VT DPS's and Valero's reliance on *AGD* as support for the proposition that, even if some utilities were put at risk, a generic solution is not proper for a problem existing only in ''isolated pockets'' is misplaced. The *AGD* court found that the Commission had not adequately justified its decision to give *all* bundled firm sales customers of a pipeline that decided to offer service under Order No. 436 the option to reduce their contract demand by 100 percent. In noting the lack of support for ''an industry-wide solution for a problem that exists only in isolated pockets,'' the court expressed concern that the remedy adopted by the Commission (''such drastic action as 100% CD reduction'' [659]) was too broad.

In Order No. 888, in contrast, the Commission has determined that it is in the public interest to give a *limited* class of utilities—those that are parties to wholesale requirements contracts that were executed on or before July 11, 1994 that do not contain an exit fee or other explicit stranded cost provision and that contain *Mobile-Sierra* clauses—an opportunity to seek to add a stranded cost provision to the contract. Thus, the narrow scope of the Commission's *Mobile-Sierra* public interest finding is a far cry from the broad remedy (100 percent CD reduction) that the court remanded in *AGD.* Indeed, it more closely resembles the type of limited generic action that the *AGD* court suggested would be proper when it stated: ''This is not to say, of course, that the Commission could not use generic rules to identify a limited class of LDCs to be entitled to reduce CD when special conditions are present.''[660]

We explained in Order No. 888 that we were making two complementary public interest findings. First, as described above, is our decision that it is in the public interest to permit public utilities to seek stranded cost amendments to existing requirements contracts with *Mobile-Sierra* clauses. Second, we found that a ''party'' to a requirements contract containing a *Mobile-Sierra* clause no longer will have the burden of establishing independently that it is in the public interest to permit the modification of such contract, but still will have the burden of establishing that such contract no longer is just and reasonable and therefore ought to be modified. We clarify that, in making this second finding, our reference to a ''party'' to a requirements contract containing a *Mobile-Sierra* clause was directed at modification of contract provisions by customers.[661] Additionally, this second finding applies to any contract revisions sought, whether or not they relate to stranded costs.[662]

We also concluded that ''if a customer is permitted to argue for modification of existing contracts that are less favorable to it than other generation alternatives, then the utility should be able to seek modification of contracts that may be beneficial to the customer.'' [663] We clarify in response to APPA and TDU Systems that this statement was not intended to imply that the Commission had made *Mobile-Sierra* findings that would permit utilities with *Mobile-Sierra* contracts to seek non-stranded cost amendments to contracts that may be favorable to a customer, based on a showing that the contracts are no longer just and reasonable. Our *Mobile-Sierra* findings as to public utility sellers apply only when utilities seek to add stranded cost provisions or make other modifications related to stranded costs. Thus, if a utility with a *Mobile-Sierra* contract initiates a section 206 proceeding in which it seeks to modify contract provisions that do not relate to stranded costs, it will have to show that it is contrary to the public interest not to modify the contract.

As we stated in Order No. 888, the most productive way to analyze contract modification issues is to consider simultaneously both the selling public utility's claims, if any, that it had a reasonable expectation of continuing to serve the customer beyond the term of the contract and the customer's claim, if any, that the contract no longer is just and reasonable and therefore ought to be modified. We said that if a customer brings a claim in a section 206 proceeding to shorten or terminate a contract, the selling public utility must bring any stranded cost claim with respect to that customer in that section 206 proceeding. Our goal is to ensure that all of the issues expected to be raised by the parties when a customer departs a utility's generation system can be efficiently litigated in one proceeding. Therefore, we have similarly required that if the customer intends to claim that the notice or termination provision of its existing requirements contract is unjust and unreasonable, it must present that claim in any proceeding brought by the selling public utility to seek recovery of stranded costs. We disagree with American Forest & Paper's argument that it is a ''no-win'' situation if a customer seeking to modify a contract must present that claim in any stranded cost proceeding brought by the selling public utility. To the contrary, providing the customer to a *Mobile-Sierra* contract with the opportunity to demonstrate that its contract is no longer just and reasonable and that its term should be shortened or eliminated could be beneficial to the customer, notwithstanding the customer's potential stranded cost obligation. As we explained in the Rule:

> [G]iven the industry circumstances now facing us, both selling utilities and their customers ought to have an opportunity to make the case that their existing requirements contracts ought to be modified. By providing both buyers and sellers this opportunity, the Commission attempts to strike a reasonable balance of the interests of all market participants.[664]]

In response to APPA's analysis of *Northeast Utilities,* it is true, as APPA asserts, that *Northeast Utilities* involved the Commission's initial review of a contract, not modification of a previously accepted and approved contract, and that the contract involved an affiliate transaction, while this rulemaking is targeted at arm's-length agreements. However, we do not believe that these differences bear on the precedential value of this case to the circumstances presented in the Rule. To the contrary, we believe that *Northeast Utilities* provides valuable guidance concerning application of the public interest standard where, as here, a failure to allow limited contract modification may harm the public interest by harming third parties.

We disagree with APPA's contention that the Commission should have applied the ''practically

[659] 824 F.2d at 1019.

[660] *Id.* at 1019–20.

[661] We note that the fact that a contract may bind a utility to a *Mobile-Sierra* standard does not mean that the customer is also bound to that standard. Unless a customer specifically waives its section 206 just and reasonable rights, the Commission construes the issue in favor of the customer.

[662] In situations in which a customer institutes a section 206 proceeding to modify a contract that binds the utility to a *Mobile-Sierra* standard, the utility may make whatever arguments it wants regarding any of the contract terms, including those unrelated to stranded costs, but will be bound to a *Mobile-Sierra* standard for contract terms that do not relate to stranded costs.

[663] FERC Stats. & Regs. at 31,664, 31,813; mimeo at 86, 521.

[664] FERC Stats. & Regs. at 31,814; *mimeo* at 522–23.

insurmountable'' standard from ''the classic 'low-rate' case, namely, *Papago*.''[665] As we have stated on several occasions, ''we do not interpret the public interest standard of review * * * as imposing on us a practically insurmountable burden in situations in which we are protecting non-parties to a contract.''[666] Additionally, we do not interpret the public interest standard as practically insurmountable in extraordinary situations such as this one where historic statutory and regulatory changes have converged to fundamentally change the obligations of utilities and the markets in which they and their customers will operate. In this circumstance, we believe the public interest test is met where the Commission determines that it is necessary to allow parties to seek contract amendments in order to protect the stability and financial integrity of the electric industry in general during the transition to competition as well as the interest of third parties affected by the transition. This type of situation simply was not addressed in *Papago*.

Congress has entrusted the Commission with the statutory responsibility to protect the public interest. As we explained in *Northeast Utilities Service Company:*[667]

> Protection of the 'public interest' provides the justification for the Commission's power to regulate public utilities under Part II [of the FPA]. Specifically, section 201(a) of the FPA declares 'that the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest' and that federal regulation of matters related to generation (to the extent provided in Parts II and III of the FPA) and of the transmission and sale at wholesale of electric energy in interstate commerce 'is necessary in the public interest.'

Consistent with our statutory obligations under the FPA, the Commission has an overriding responsibility to protect non-parties affected by *Mobile-Sierra* contracts, including consumers, to ensure that matters entrusted to our jurisdiction function smoothly during the restructuring transition, and to fairly balance the interests of utilities and customers during the transition.[668] The ability to meet our overarching public interest responsibilities would be virtually precluded if we must apply a practically insurmountable standard of review before we can take action to address industry-wide transition issues.

Rehearing Requests Supporting Limited Transition Period

Several entities request rehearing of the Commission's decision not to establish a three-to five-year period within which stranded cost recovery could be raised. They assert that if the Commission truly views stranded investment as a transition process, the transition should not be an extended one.[669]

Commission Conclusion

The Commission will deny the requests for rehearing on this point. As we explained in Order No. 888, although we considered limiting the period within which stranded cost recovery could be raised, there is no uniform time remaining on requirements contracts executed on or before July 11, 1994.[670] As a result, any limitation on the period in which parties could propose amendments covering stranded costs, such as three years, would affect market participants unequally. Those with long terms remaining on their contracts could object that immediately addressing the issue would not be cost effective. A utility with a long remaining term might not even seek stranded cost recovery depending on the competitive value of its assets near the end of the contract term.[671] However, such a utility would invariably seek to preserve its option to seek stranded cost recovery if its failure to do so within a short period resulted in a waiver of its right to do so. Having determined that it is generally appropriate to leave in place existing requirements contracts, it is not then reasonable to create a time limitation on stranded cost recovery that would encourage a supplier to seek early termination in order to preserve its stranded cost recovery rights.

On this basis, we believe that we have adequately explained the rationale for our decision to allow stranded cost claims to be raised at any time prior to the termination of the contract, instead of within three to five years of the effective date of the Rule.

6. Recovery of Stranded Costs Caused by Retail-Turned-Wholesale Customers

In Order No. 888, we concluded that this Commission should be the primary forum for addressing the recovery of stranded costs caused by a retail-turned-wholesale customer.[672] We stated that if such a customer is able to reach a new generation supplier because of the new open access (through the use of a FERC-filed open access transmission tariff or through transmission services ordered pursuant to section 211 of the FPA), any costs stranded as a result of this wholesale transmission access should be viewed as ''wholesale stranded costs.'' We explained that there is a clear nexus between the FERC-jurisdictional transmission access requirement and the exposure to non-recovery of prudently incurred costs and that, in these circumstances, this Commission should be the primary forum for addressing recovery of such costs.[673]

We said we will not be the primary forum for stranded cost recovery in situations in which an existing municipal utility annexes territory served by another utility or otherwise expands its service territory. We indicated that in these situations there is no direct nexus between the FERC-jurisdictional transmission access requirement and the exposure to non-recovery of prudently incurred costs. The risk of an existing municipal utility expanding its territory was a risk prior

[665] APPA at 49. It should be noted that, as the Northeast Utilities court indicated, the *Papago* court's description of the public interest standard as ''practically insurmountable'' was dictum. 55 F.3d at 691. Further, *Papago* did not involve a contractual arrangement for rate revision where the parties ''by broad waiver * * * eliminate both the utility's right to make immediately effective rate changes under § 205 and the Commission's power to impose changes under § 206, except the indefeasible right of the Commission under § 206 to replace rates that are contrary to the public interest.'' *Papago*, 723 F.2d at 953. Instead, *Papago* involved a contractual regime that ''contractually eliminate[d] the utility's right to make immediately effective rate changes under § 205 but [left] unaffected the power of the Commission under § 206 to replace not only rates that are contrary to the public interest but also rates that are unjust, unreasonable, or unduly discriminatory or preferential to the detriment of the contracting purchaser.'' *Id. See also id.* at 953–54.

[666] Southern Company Services, Inc., 67 FERC ¶ 61,080 at 61,228 (1994); *see also* Florida Power & Light Company, 67 FERC ¶ 61,141 at 61,398–99 (1994).

[667] 66 FERC ¶ 61,332 at 62,081, *reh'g denied*, 68 FERC ¶ 61,041 (1994).

[668] 66 FERC at 62,081–83; *see also Southern*, 67 FERC at 61,228–29.

[669] *E.g.*, Central Montana EC, Central Illinois Light.

[670] It is not possible for the Commission to come up with a reliable yardstick of the remaining terms of existing requirements contracts. The Commission's files do not categorize rate schedules as requirements, coordination and transmission-only contracts. Moreover, there is no uniform format for requirements contracts. Many have evergreen provisions, the terminology of which varies from contract-to-contract (*e.g.*, some may be year-to-year, others may roll over).

[671] The value of its assets could vary over time as new technologies emerge, fuel costs fluctuate, or environmental requirements change.

[672] FERC Stats. & Regs. at 31,818–19; *mimeo* at 534–37.

[673] We indicated that we will require the same evidentiary demonstration for recovery of stranded costs from a retail-turned-wholesale customer (and will apply the same procedures for determining stranded cost obligation) as that required in the case of a wholesale requirements customer.

to the Energy Policy Act and prior to any open access requirement.

Nevertheless, we did express concern that there may be circumstances in which customers and/or utilities could attempt, through indirect use of open access transmission, to circumvent the ability of any regulatory commission—either this Commission or state commissions—to address recovery of stranded costs. We reserved the right to address such situations on a case-by-case basis.

Rehearing Requests Opposing Retail-Turned-Wholesale Jurisdiction

A number of entities challenge the Commission's assertion that costs associated with retail-turned-wholesale customers would not be stranded but for the FERC-jurisdictional transmission access requirement. They assert that the condition precedent to municipalization is the operation of a state process, and thus that it cannot be the case that the recovery of costs caused by a retail-turned-wholesale customer is ''not subject to regulation by the States.'' They submit that such costs would not be stranded but for the action of state legislators or state regulators in granting authority for the customer's status change. They argue that any nexus that the Commission's authority under the FPA has to wholesale transmission services subsequently provided to the new wholesale customer is entirely derivative of the state's action.[674]

A number of entities argue that jurisdiction over costs that are stranded when a retail customer becomes a wholesale customer should be left to the states because the facilities used to provide retail service to these retail customers were subject to state jurisdiction and were included in retail rate base when the service was rendered.[675] They argue that because the Commission had no jurisdiction over the public utility facilities and costs incurred to serve retail-turned-wholesale customers, it has no jurisdiction to address those public utility costs if they become stranded. Thus, according to these entities, the conversion of the customer from retail to wholesale does not simultaneously effectuate a conversion of the costs from retail to wholesale.

AR Com and MO/KS Coms submit that jurisdiction over the costs incurred for historical retail customers does not shift unless the parties themselves make those costs a part of their new wholesale contract. NY Com submits that the Commission should recognize the states' jurisdiction to set the *level* of stranded costs associated with retail-turned-wholesale customers to be recovered in wholesale transmission rates set by FERC. FL Com asserts that state authorities are in a better position to assess the extent of stranded facilities and their costs, and that the Commission's involvement should be limited to that requested by a state by petition.

OH Com states that the Commission's position on stranded costs associated with retail-turned-wholesale customers invites second-guessing of state commission determinations and encourages forum shopping by introducing more than one stranded cost treatment within a single state jurisdiction. It expresses concern that utilities may seek to creatively disaggregate into generation, transmission, and distribution companies in ways to deliberately recast traditional retail relationships as wholesale in an effort to obtain favorable regulatory treatment of stranded costs.

IN Com submits that Order No. 888's treatment of stranded costs associated with retail-turned-wholesale customers will discourage state legislatures from making municipalization more available. VT DPS and Valero argue that the threat of a stranded cost surcharge will erect a new barrier to the formation of municipal utilities. They note that the Rule refers to one commenter's observation that, if Otter Tail could have made a stranded cost claim against the municipal utility that Elbow Lake planned to create, Otter Tail would not have needed to refuse to wheel and there would never have been an *Otter Tail* case. They submit that the Commission never addressed whether, or why, it believed the point to be wrong.

VT DPS and Valero also assert that the Rule represents a major inconsistency with prior Commission treatment of municipalization. They submit that the Commission historically promoted franchise competition between municipalities and utilities by holding tariff provisions that restrict such competition to be anticompetitive and unreasonable.[676]

American Forest & Paper submits that recovery of 100 percent of stranded costs caused by municipalization is inconsistent with the Commission's actions in the natural gas industry, where the Commission has encouraged competition at the retail level through competitive bypass and has not created barriers to competitive entry by imposing transition charges or exit fees on converting customers.[677]

Nucor objects that the Rule does not address the substantive findings, the common sense rationale, or the jurisdictional distinction drawn in *United Illuminating.*[678] It contends that the Commission's observation in Order No. 888 that there may not be a state regulatory forum for the recovery of stranded costs associated with retail-turned-wholesale customers and hence that the Commission should be the primary forum for addressing such stranded costs is flawed because there always is a state forum to address such cost recovery (the adequacy of the relief provided is a very distinct issue) and open access transmission does not and cannot cause retail competition to occur.[679]

Commission Conclusion

We will reject the requests for rehearing of our decision to be the primary forum for addressing the recovery of stranded costs caused by retail-turned-wholesale customers. We find the requests for rehearing on this issue unpersuasive. While it may be the case, as some entities suggest, that state action is a condition precedent to municipalization, the rehearing petitions ignore the fact that the Rule covers situations in which open access is *also* a condition precedent to the municipalized customers leaving their existing supplier's system. Order No. 888 does not propose that the Commission be the primary forum for stranded cost recovery for all cases of municipalization. Instead, our holding is limited to those cases in which the new wholesale entity uses Commission-mandated transmission access to obtain new power supply on behalf of retail customers that were formerly supplied

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[674] *E.g.*, NARUC, TAPS, Nucor, Suffolk County, IL Com, Multiple Intervenors, APPA, CAMU, WI Com, NASUCA.

[675] *E.g.*, ELCON, IL Com, IN Com, American Forest & Paper, AR Com, MO/KS Coms, NJ BPU, Suffolk County, WY Com, VA Com, FL Com, NARUC, TAPS.

[676] VT DPS and Valero cite in this regard Florida Power & Light Company, 8 FERC ¶ 61,121 (1979); Power Authority of the State of New York v. FERC, 743 F.2d 93 (2d Cir. 1984); Metropolitan Transportation Authority v. FERC, 796 F.2d 584 (2d Cir. 1986).

[677] American Forest & Paper cites in support of its position Great Lakes Gas Transmission Limited Partnership, 68 FERC ¶ 61,376 (1994).

[678] United Illuminating Company, 63 FERC ¶ 61,212, *reh'g denied*, 64 FERC ¶ 61,087 (1993) (*United Illuminating*).

[679] *See also* Suffolk County Rehearing (Commission's analysis in *United Illuminating* was correct; nothing has changed to warrant the Commission's rejection of that analysis).

power by the utility providing the transmission service.[680]

As we explained in Order No. 888, in such cases there is a direct nexus between the FERC-jurisdictional transmission access requirement and the exposure to non-recovery of costs stranded as a result of this wholesale transmission access. Thus, the stranded costs associated with retail-turned-wholesale customers for which Order No. 888 provides an opportunity for recovery would not have been incurred *but for* the action of this Commission in requiring a utility to make unbundled transmission services available. In these cases, the former bundled retail customers of the historical supplying utility (now the bundled retail customers of the new municipal system) would not have obtained access to new power supply *but for* the Commission's order mandating transmission. Without the regulatory mandate to provide access, the utility would have indirectly continued sales to the same retail customers because the new municipal utility purchasing power on the retail customers' behalf would have had no way to reach other power suppliers. In this situation, there would be no stranded generation costs. In other words, the creation of a municipal utility intermediary to purchase power at wholesale would not, by itself, trigger stranded costs. Rather, it is the access from the historical supplier of the bundled retail customers that is the condition precedent to reaching other power suppliers and thereby triggering stranded costs. Therefore, there is a clear causal nexus between the stranded costs and the availability and use of the tariff *required by the Commission*.

Costs that are exposed to nonrecovery when a retail customer or a newly-created wholesale power sales customer ceases to purchase power from the utility and *does not* use the utility's transmission system to reach a new generation supplier (*e.g.*, through self-generation or use of another utility's transmission system) do not meet the definition of ''wholesale stranded costs'' for which the Rule provides an opportunity for recovery. Such costs are outside the scope of the Rule because such costs would not be stranded as a direct result of the new open access.

In response to the argument that conversion of a customer from retail to wholesale would not simultaneously effectuate a conversion of the costs from retail to wholesale, we believe this argument confuses the issue. We note that we have defined stranded costs as wholesale or retail on the basis of whether wholesale or retail open access is the cause of the costs being stranded, not on the basis of the original retail or wholesale characteristic of the costs. Thus, even though costs may have been originally incurred as retail-related costs, the precipitating event that results in such costs being stranded in the retail-turned-wholesale customer scenario is the use by the new wholesale customer of the Commission-mandated tariff. When a customer is able to use the Commission-required tariff to reach another generation supplier, it causes the utility to incur an economic cost in providing transmission service that is equal to the foregone revenues that the utility reasonably expected to receive under a state regulatory regime. Thus, because of the causal nexus between the use of a former supplying utility's Commission-mandated transmission tariff and the potential for foregone revenues by that utility as a result of the Commission-required access, the costs stranded by a retail-turned-wholesale customer are properly viewed as economic costs that are jurisdictional to this Commission.

In response to those entities that express concern that the Commission's position on stranded costs associated with retail-turned-wholesale customers invites second-guessing of state commission determinations, we emphasize that we have assumed primary authority to address such costs only in a limited category of cases where there is a direct nexus between the availability of Commission-required open access and the stranding of costs when the former customer uses the former supplying utility's transmission system (through its open access tariff or a section 211 order) to reach a new supplier. We indicated in Order No. 888 that if the state has permitted any recovery from departing retail-turned-wholesale customers, such amount will not be stranded for purposes of this Rule. We will deduct that amount from the costs for which the utility will be allowed to seek recovery under this Rule from the Commission. In so doing, however, we are not second-guessing the states as to what a utility may recover under state law. Additionally, we will give great weight in our proceedings to a state's view of what might be recoverable.

We also reject the argument that the Commission's position on stranded costs associated with retail-turned-wholesale customers encourages forum shopping. To the contrary, as we said in Order No. 888, to avoid forum shopping and duplicative litigation of the issue, we expect parties to raise claims before this Commission in the first instance. We believe that this Commission should be the primary forum because, without the open access provided by the Rule, the new municipal utility would not be able to reach a new supplier and, as a result, would not cause the utility to incur stranded costs (as defined in this Rule).

We reject as misplaced arguments that the Rule represents a major inconsistency with the Commission's historical promotion of franchise competition between municipalities and utilities and that it will discourage municipalization.[681] It continues to be the Commission's policy to encourage competition. Indeed, the goal of Order No. 888 is to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the Nation's electricity consumers. However, the purpose of the stranded cost policy is neither to encourage nor to discourage municipalization, but rather to facilitate a fair transition to competition and to ensure stability in the industry during that transition. As we discuss elsewhere in this order, we believe that this Commission must address the recovery of the costs of moving from a monopoly-regulated regime to one in which all sellers can compete on a fair basis and in which electricity is more competitively priced. On this basis, we believe that if a new wholesale entity such as a municipal utility uses Commission-required open access to reach a new supplier on behalf of its retail customers (previously retail customers of the former supplier), the former supplying utility should be given an opportunity to recover legitimate, prudent and verifiable costs that it

[680] In the case of municipalization, the bundled retail customers of a local utility become the bundled retail customers of the new municipal utility. As explained above, we call this a ''retail-turned-wholesale customer'' situation because the new municipal entity in effect ''stands in the shoes'' of the retail customers for purposes of obtaining wholesale transmission access and new power supply.

[681] In response to VT DPS and Valero, we note that whether or not Otter Tail may have agreed to wheel power for the municipal utility that Elbow Lake planned to create if Otter Tail could have made a stranded cost claim against that municipal utility is of no moment to the Commission's decision in Order No. 888 to allow utilities the opportunity to seek recovery of stranded costs associated with retail-turned-wholesale customers. The Court in *Otter Tail* did not address the stranded cost issue because it was not presented in that case. Nor was the Court presented with the extraordinary circumstances—the historic statutory and regulatory changes, including the requirement of open access, that have converged to fundamentally change the obligations of utilities and the markets in which they operate—that have justified this Commission's Order No. 888 stranded cost policy.

incurred under the prior regulatory regime to serve that customer.

In response to American Forest & Paper's argument that recovery of 100 percent of stranded costs caused by municipalization is inconsistent with the Commission's policy in the natural gas industry of allowing competitive bypass without imposing transition charges or exit fees on converting customers, we note that industrial gas customers who bypass a local distribution company's (LDC) facilities do not escape transition costs quite so easily as suggested by American Forest & Paper. It is true that, when the end user bypasses the LDC to reach an interstate pipeline different from the pipeline serving the LDC, the Commission views the bypass as a risk of competition from which the LDC should not be shielded.[682] However, when the end user bypasses the LDC to reach the same interstate pipeline that serves the LDC, the Commission may take certain actions to minimize adverse effects on the LDC and its remaining customers.[683] Moreover, an end user that bypasses an LDC to reach the same pipeline that serves the LDC would, in any event, be allocated a share of the pipeline's gas supply realignment costs (if any), since those costs are allocated based on current contract demand (or usage).[684] Accordingly, we see no inconsistency between our bypass policy for the natural gas industry and Order No. 888's treatment of stranded costs associated with retail-turned-wholesale customers. Similar to our refusal to shield LDCs from the adverse effects of an end user's bypass to reach a different pipeline than serves the LDC, Order No. 888 does not provide an opportunity for stranded cost recovery where a retail-turned-wholesale customer uses another utility's transmission system to reach a new supplier. As we note above, the opportunity for recovery of stranded costs associated with retail-turned-wholesale customers is limited to those cases in which the former retail customer obtains (either directly or through another wholesale transmission purchaser) unbundled transmission services from its former supplying utility. In the case of an end use customer bypassing the LDC to reach the same pipeline that serves the LDC, the end use customer would similarly be allocated a share of the pipeline's gas supply realignment costs. As a result, American Forest & Paper's attempt to rely on the Commission's gas bypass policy is misplaced.

We also disagree with those entities that argue that the Commission has failed to adequately distinguish Order No. 888's treatment of stranded costs associated with retail-turned-wholesale customers with the Commission's decision in *United Illuminating.* As we stated in Order No. 888, we recognize that we took a different approach to stranded cost recovery associated with retail-turned-wholesale customers in *United Illuminating,* where we suggested that state and local regulatory authorities or the courts should be able to provide an adequate forum to address retail franchise matters, including recovery of stranded costs caused by municipalization, but said we would consider revisiting the question if United Illuminating could demonstrate the lack of a forum.[685] However, we explained that since the issuance of that decision we have had an opportunity to re-analyze the nature of the stranded cost problem when a retail customer becomes a wholesale customer, including the potential that there might not be a state regulatory forum for recovery of such costs. In these circumstances, we have determined that where such costs are stranded as a direct result of Commission-mandated wholesale transmission access, these costs should be viewed as costs of the transition to competitive wholesale bulk power markets and this Commission should be the primary forum for addressing their recovery.

In response to Nucor's objection that there always is a state forum to address stranded cost recovery associated with retail-turned-wholesale customers, with the adequacy of the relief being a distinct issue, we clarify that our primary concern in retail-turned-wholesale situations is not whether there is an adequate state regulatory forum for the recovery of stranded costs associated with retail-turned-wholesale customers. Rather, our primary concern is that wholesale customers (whether or not formerly retail) should be responsible for the costs incurred to meet their power needs that are stranded when they use the wholesale transmission ordered by this Commission to reach new suppliers. Our decision to be the primary forum in the case of stranded costs associated with retail-turned-wholesale customers is based on the causal nexus between regulatory-mandated wholesale transmission access and the stranding of costs when a new municipal utility uses such access to obtain new power supply on behalf of retail customers previously served by the former supplying utility.

Rehearing Requests Seeking Expansion of Retail-Turned-Wholesale Jurisdiction

Other entities seek rehearing of the Commission's decision not to be the primary forum for stranded cost recovery in situations in which an existing municipal utility annexes territory served by another utility or otherwise expands its service territory.[686] A number of them argue that the loss of existing retail customers through municipal annexations or expansions is no different from the loss of retail customers through new municipalization because existing municipal systems are likely to use Commission-jurisdictional open access transmission to obtain resources to supply power to the annexed loads.[687] They submit that, just as with newly-municipalized customers, such costs would not be stranded but for the action of this Commission.

Some of these entities express concern that the Rule will encourage retail-turned-wholesale transactions to be undertaken as annexations rather than through the formation of new entities to avoid stranded costs. [688] Public Service Co of CO contends that Order No. 888, in conjunction with the Commission's section 211 order in American Municipal Power Ohio, Inc.,[689] may facilitate municipal annexations by enabling municipal systems to serve new territory through the establishment of second delivery points.

Coalition for Economic Competition and Puget also argue that the Commission must consider stranded

[682] Texas Gas Transmission Corporation, 65 FERC ¶ 61,275 (1993).

[683] Texas Gas Transmission Corporation, 69 FERC ¶ 61,245, *reh'g,* 70 FERC ¶ 61,207 (1995) (requiring pipeline to offer LDC a reduction in its contract demand).

[684] *See* Southern Natural Gas Company, 75 FERC ¶ 61,046 at 61,158 (1996); Arcadian Corporation v. Southern Natural Gas Company, 67 FERC ¶ 61,176 at 61,538 (1994). *See also United Distribution Companies,* 88 F.3d at 1181. As the *United Distribution Companies* court noted, the Commission has given an LDC relief (and required the bypassing customer to bear its share of transition costs) if the LDC can show a direct nexus between the bypass and the pipeline, although the Commission has declined to adopt a generic rule addressing this issue. 88 F.3d at 1180–81.

[685] 63 FERC at 62,583–84.

[686] *E.g.,* EEI, SoCal Edison, Centerior, Atlantic City, PSE&G, Puget, Public Service Co of CO, Coalition for Economic Competition.

[687] *E.g.,* EEI, SoCal Edison, PSE&G, Puget, Public Service Co of CO, Coalition for Economic Competition. Coalition for Economic Competition suggests, for example, that villages and large industrial customers may opt to join existing municipal systems that, in most cases, will use Commission-jurisdictional transmission tariffs to obtain resources to supply power to the annexed loads.

[688] *E.g.,* EEI, Coalition for Economic Competition, Atlantic City, Puget, Public Service Co of CO.

[689] 74 FERC ¶ 61,086, *final order directing transmission service,* 76 FERC ¶ 61,265 (1996).

costs that arise from municipal expansion in order to satisfy its statutory obligation under the FPA to ''set just and reasonable'' rates. They contend that there is no justification for charging one rate to former retail customers taking transmission services through a new municipal utility and another rate to those taking service through municipal annexation or through use of another utility's transmission system.

PSE&G suggests that the distinction between new municipalization on the one hand and municipal annexation or expansion on the other hand may lead to unnecessary controversy and litigation as entities wrangle over whether a given expansion/annexation is really an expansion or a municipalization. It says that a situation could arise where a municipality serves one town in order to serve thousands of additional customers in a second town. According to PSE&G, it is not clear from the Rule whether the Commission would consider this an expansion of a municipality's service territory or a new municipalization.

Puget submits that the stranded cost recovery mechanism must not be subject to being frustrated by simple artifices such as having the new supplier (instead of the departing customer) request and contract for transmission service. SoCal Edison seeks clarification of the Commission's authority to mandate stranded cost recovery if a retail customer disconnects from a utility's system and accesses another generation supplier by interconnecting with a public power entity (who in turn would interconnect with a neighboring jurisdictional utility). It asks the Commission to clarify that such a transaction effectively constitutes a municipalization, not an expansion of a service territory, and that the Commission, under FPA section 211, can compel the recovery of stranded costs by having the ''new'' jurisdictional utility assess a stranded cost charge and pass the revenues on to the utility from whose system the customer departed.

SoCal Edison seeks several additional clarifications. It states that it understands that the Commission's primary forum status in no way prevents or interferes with a state's authority to order stranded cost recovery from departing retail customers. If this is not the case, SoCal Edison seeks rehearing on this issue. SoCal Edison also asks the Commission to clarify that the Commission retains the discretion to defer to a state stranded cost calculation methodology if appropriate to do so on the facts of a particular case.

Commission Conclusion

We have carefully reviewed the arguments made by petitioners seeking rehearing of our decision not to be the primary forum for stranded cost recovery in the case of municipal annexations. Based on that review we have decided to reconsider our decision. This conclusion is based in large part upon the very significant similarities between the creation of a *new* municipal utility system (also referred to as municipalization) and the expansion of an *existing* municipal utility system (*e.g.*, through annexation of additional retail service territory). We recognize that the *same nexus* to Commission-required transmission access that forms the basis for our decision to allow a utility to seek stranded cost recovery in cases of new municipalization—use of the former supplying utility's transmission system—is likely to be present in some cases of municipal annexation. In the case of both new municipalizations and annexations, the bundled retail customers of a local utility become the bundled retail customers of a municipal utility (in one case a new municipal utility, in the other an existing municipal utility) *that will use the transmission system of the retail customers' former supplier in order to access other suppliers.*

As we explain above, in a ''retail-turned-wholesale customer'' situation, such as the creation of a municipal utility system, a newly-created entity becomes a wholesale power purchaser on behalf of the retail customers. It is the conduit by which retail customers, if they cannot obtain direct retail access, can reach power suppliers other than their historical local utility power supplier. Although the retail customers remain bundled retail customers, in that they become the bundled customers of the new entity, we call this a ''retail-turned-wholesale customer'' situation because the new entity in effect ''stands in the shoes'' of the retail customers for purposes of obtaining wholesale transmission access and new power supply. The same analogy applies to newly-annexed customers; they become ''new'' wholesale customers in the sense that the wholesale entity obtains transmission and new power supply on their behalf.

Accordingly, we clarify that this Commission will be the primary forum for addressing the recovery of stranded costs if an existing municipal utility uses the transmission system of its annexed retail customers' former supplier to access new suppliers to serve the annexed load. As long as Commission-required transmission access (the former supplier's open access tariff or transmission services ordered under FPA section 211) is the vehicle that enables an existing municipal utility to obtain power supplies to serve annexed loads, we believe that any costs stranded as a result of this wholesale transmission access are properly viewed as economic costs that are jurisdictional to this Commission. In such a case, the bundled retail customers that are annexed by an existing municipal utility would, through the municipal utility, use the transmission system of their former supplier to obtain access to new supplies and thereby expose their former supplier to non-recovery of prudently incurred costs. As in the case of new municipal systems that use the transmission system of their retail customers' former supplier, such costs would not be stranded *but for* the action of this Commission in requiring a utility to make unbundled transmission services available.[690]

Just as we will not be the primary forum for stranded cost recovery for *all* new municipalizations, so also we will not be the primary forum for stranded cost recovery for *all* cases of municipal annexation. Instead, our holding is limited to those cases in which the existing municipal system uses Commission-mandated transmission access from the annexed customers' former supplying utility to obtain power from a new supplier. Costs that are exposed to nonrecovery when an existing municipal utility *does not* use the transmission system of the retail customers' former supplier to reach a new generation supplier (*e.g.*, through self-generation or use of another utility's transmission system) do not meet the definition of ''wholesale stranded costs'' for which the Rule provides an opportunity for recovery. Such costs are outside the scope of the Rule because such costs would not be stranded as a direct result of Commission-required transmission access.

[690] SoCal Edison requests clarification that a transaction in which a retail customer disconnects from a utility's system and accesses another generation supplier by interconnecting with a public power entity, who in turn would interconnect with a neighboring jurisdictional utility, constitutes a municipalization, not an expansion of a service territory. Because we have decided to treat municipal annexations (or expansions) and new municipalizations similarly for purposes of stranded cost recovery under the Rule, SoCal Edison's request is moot to the extent that it envisions a scenario in which the former supplier's transmission system is used to access a new generation supplier. However, as discussed below, the Rule would not provide an opportunity to seek recovery of stranded costs if the municipal entity in the scenario described by SoCal Edison *does not* use the former supplier's transmission system.

We reject as misplaced the argument that the Commission, by failing to address costs that arise if a municipal utility (whether a new municipal utility or an existing municipal utility that annexes additional retail customer territory) does not use the historical supplying utility's transmission system, has not met its statutory obligation to ''set just and reasonable'' rates. The Commission in this rulemaking has not determined any utility's just and reasonable rates. Further, Order No. 888 does not by its terms bar the recovery of costs that do not result from the use of Commission-required transmission access. Utilities may, as before, seek recovery of such non-open access-related costs on a case-by-case basis in individual rate proceedings. The Commission will not prejudge those issues here.

As we indicated in Order No. 888, we also are concerned that there may be circumstances in which customers and/or utilities could attempt, through indirect use of open access transmission, to circumvent the ability of any regulatory commission—either this Commission or state commissions—to address recovery of stranded costs.[691] We reiterate that we reserve the right to address such situations on a case-by-case basis.

We share the concern expressed by Puget that a retail-turned-wholesale customer should not be allowed to avoid any stranded cost obligation that it may have under Order No. 888 simply by having its new supplier be the entity that requests and contracts for transmission service from the former supplying utility. We clarify that the opportunity for recovery of stranded costs associated with retail-turned-wholesale customers under Order No. 888 applies if the transmission system of the former supplier is used to transmit the newly obtained power supplies to the departing retail customer, regardless of whether the customer *or* its new supplier is the actual entity that requests and contracts for the unbundled transmission service. We have revised the definition of ''wholesale stranded cost'' in section 35.26(b)(1)(ii) accordingly to include the situation in which the retail customer subsequently becomes, either directly or through another wholesale transmission purchaser, an unbundled wholesale transmission services customer of the former supplying utility.

We clarify in response to SoCal Edison's request that our decision to be the primary forum for recovery of stranded costs from retail-turned-wholesale customers is not intended to prevent or to interfere with the authority of a state to permit any recovery from departing retail customers, such as by imposing an exit fee prior to creating the wholesale entity. As we indicated in Order No. 888, if the state has permitted any such recovery from a departing retail-turned-wholesale customer, that amount will not in fact be stranded. Accordingly, we will deduct that amount from the costs for which the utility will be allowed to seek recovery from this Commission.[692]

We clarify in response to SoCal Edison's request that the Commission has the discretion to defer to a state stranded cost calculation methodology. However, because we recognize that state retail access plans may present questions that need to be addressed on a case-by-case basis, we will consider whether to exercise that discretion on a case-by-case basis.

7. Recovery of Stranded Costs Caused by Retail Wheeling

In Order No. 888, we concluded that both this Commission and the states have the legal authority to address stranded costs that result when retail customers obtain retail wheeling in order to reach a different generation supplier, and that utilities are entitled, from both a legal and a policy perspective, to an opportunity to recover all of their prudently incurred costs.[693] We explained that this Commission's authority to address retail stranded costs (*i.e.*, stranded costs associated with retail wheeling customers) is based on our jurisdiction over the rates, terms, and conditions of unbundled retail transmission in interstate commerce by public utilities, and that the authority of state commissions to address retail stranded costs is based on their jurisdiction over local distribution facilities and the service of delivering electric energy to end users. Because it is a state decision to permit or to require the retail wheeling that causes stranded costs to occur, we decided we generally will leave it to state regulatory authorities to deal with any stranded costs occasioned by retail wheeling. The only circumstance in which we will entertain requests to recover stranded costs caused by retail wheeling is when the state regulatory authority[694] does not have authority under state law to address stranded costs when the retail wheeling is required. In such a case, we will permit a utility to seek a customer-specific surcharge to be added to an unbundled transmission rate.

We noted that most states have a number of mechanisms for addressing stranded costs caused by retail wheeling. We indicated that rates for services using facilities used in local distribution to make a retail sale are state-jurisdictional, and that states will be free to impose stranded costs caused by retail wheeling on facilities or services used in local distribution. We also said that states may use their jurisdiction over local distribution facilities or services to recover so-called stranded benefits.

We stated that we believe our approach to stranded costs associated with retail wheeling customers represents an appropriate balance between federal and state interests that ensures that the rates for transmission in interstate commerce by public utilities (except in a narrow circumstance) will not be burdened by retail costs.

We expressed concern about the cost-shifting potential in a holding company or other multi-state situation, where denial of retail stranded cost recovery by a state regulatory authority could, through operation of the reserve equalization formula in a Commission-jurisdictional intra-system agreement, inappropriately shift the disallowed costs to affiliated operating companies in other states. We said that we will deal with such situations if they arise pursuant to public utility filings under section 205 or complaints under section 206. Thus, the need to amend a jurisdictional agreement to prevent stranded costs associated with retail wheeling customers from being shifted to customers in other states will be addressed on a case-by-case basis. We encouraged the affected state commissions in such situations to seek a mutually agreeable approach to this potential problem. If such a consensus solution resulted in a filing to modify a jurisdictional agreement, we indicated that we would accord such a proposal deference, particularly if other interested parties support the filing. In the event that the state commissions and other interested parties cannot reach consensus that would prevent cost shifting, we said that the Commission would ultimately have to resolve the

[691] FERC Stats. & Regs. at 31,819; *mimeo* at 536–37.

[692] FERC Stats. & Regs. at 31,819; *mimeo* at 537.

[693] FERC Stats. & Regs. at 31,824–26; *mimeo* at 553–58.

[694] ''State regulatory authority'' has the same meaning as provided in section 3(21) of the FPA:

'State regulatory authority' has the same meaning as the term 'State commission', except that in the case of an electric utility with respect to which the Tennessee Valley Authority has ratemaking authority (as defined in section 3 of the Public Utility Regulatory Policies Act of 1978), such term means the Tennessee Valley Authority.

appropriate treatment of such stranded costs.

Rehearing Requests Opposing Any Commission Involvement in Stranded Costs Associated With Retail Wheeling Customers

A number of entities dispute the Commission's statement that both it and the states have the legal authority to address stranded costs that result from retail wheeling. Central Illinois Light contends that the Commission's claim of dual jurisdiction is inconsistent with *FPC* v. *Southern California Edison Company*.[695] It says that the court in that case recognized that Congress meant to draw a bright line easily ascertained between state and federal jurisdiction, making unnecessary case-by-case analysis. Central Illinois Light asserts that the Commission has stepped over the bright line into the states' exclusive jurisdiction over retail rates.

IA Com seeks rehearing of the Commission's assertion of concurrent jurisdiction with state authorities over stranded costs associated with retail wheeling customers on the ground that it is based on the Commission's erroneous assertion of jurisdiction over unbundled retail transmission.

IL Com says that regardless of whether the Commission's claim of jurisdiction over retail transmission is upheld, the Commission's ruling that there is joint jurisdiction over retail stranded costs is in error. According to IL Com, the Commission has no authority over such stranded costs. IL Com also disputes the Commission's characterization of the derivation of state authority to address such stranded costs. It says that state commission authority does not derive only from states' jurisdiction over local distribution facilities and the service of delivering electric energy to end users. IL Com submits that state commission authority to address retail stranded costs derives from the existence of state commission jurisdiction over the facilities and costs at the time of their incurrence.

A number of entities contend that Commission jurisdiction over transmission facilities used in interstate commerce does not give it jurisdiction over stranded investment in retail generating assets.[696] Several argue that the fact that a retail wheeling customer might need transmission access from its former supplier does not change the character of the costs that are stranded. They maintain that retail stranded costs are not costs of providing unbundled transmission service, but are costs associated with providing what was formerly bundled retail service, over which the Commission has no jurisdiction.[697]

Several entities argue that it is solely the action of the state that allows a given utility's retail customers to seek alternative sources of supply; therefore, there is no nexus between the Commission's wholesale transmission rule and any costs that might be stranded by a state-established customer choice regime.[698]

A number of entities submit that the provision of FPA section 201 that federal regulation is ''to extend only to those matters which are not subject to regulation by the States'' bars any attempt by the Commission to displace or supplant an admittedly legitimate exercise of state authority over retail stranded costs.[699] NASUCA submits that all state commissions have the authority to establish just and reasonable rates for the retail electric utilities in their respective jurisdictions.[700] It maintains that only state regulators are in a position to rule on the treatment of costs that were allowed in retail rates pursuant to state laws; the Commission has no knowledge or expertise regarding the specific state legal frameworks in which these costs were included in rates. NY Com argues that the Commission does not have jurisdiction to determine the rate treatment of costs devoted to retail service and, thus, lacks authority to allow recovery if a state decides not to do so.

VA Com argues that section 201(b)(1) of the FPA restricts the Commission's jurisdiction to wholesale sales. It says that a departing retail customer remains a retail customer, regardless of the supplier. VA Com concludes that no portion of the transaction is a wholesale sale, and that there are no wholesale costs associated with a retail wheeling transaction.[701]

A number of entities seek rehearing of the Commission's decision that it will entertain stranded cost claims when the state regulatory authority does not have authority under state law to address stranded costs when the retail wheeling is required.[702] NARUC submits that Congress did not intend the Commission to become involved in adjudicating legal questions regarding the breadth of state law authority granted state commissions by their legislatures. NARUC expresses concern that the Commission would second-guess a state cost recovery determination and promote forum shopping. Once a balance has been struck at the state level concerning the terms of restructuring, NARUC submits that it is inconceivable that the Commission would have either the desire or authority to second-guess a state's legislative and regulatory processes.

Several entities object that the Commission effectively would authorize recovery of stranded costs associated with a retail wheeling customer if a state legislature withholds from the state regulatory agency the authority to approve stranded cost recovery.[703] They submit that just because a state has not given its regulatory commission the authority to impose stranded costs in the case of retail wheeling does not confer jurisdiction on the Commission to impose such charges. They contend that the state legislature should be the final arbiter of state policy. IL Com submits that if a state legislature chooses not to give its state commission the authority to act on stranded costs, ''that can be taken as a clear indication that the state's legislature most certainly does *not* want FERC to address them.'' [704] Central Illinois Light objects that the Commission has offered no reason why it will accept the decision

[695] 376 U.S. 205, 215–16 (1964).

[696] *E.g.*, Central Illinois Light, IN Consumer Counselor, IN Consumers, Nucor, FL Com, WI Com, VA Com, AR Com, MO/KS Com, OH Com, APPA. For example, FL Com asserts that costs for facilities that are currently under the jurisdiction of state authorities do not become the Commission's jurisdiction because retail wheeling is instituted; in most cases, the states approved both the construction and the cost recovery for these facilities under bundled rate structures. FL Com submits that the states are in a better position to judge the extent and value of assets that may become stranded as a result of retail wheeling.

[697] *E.g.*, APPA, AR Com, MO/KS Coms, OH Com.

[698] *E.g.*, NARUC, TAPS.

[699] *E.g.*, NASUCA, NY Com, WY Com, NARUC. The Consumer's Utility Counsel Division of the Georgia Governor's Office of Consumer Affairs filed comments on June 24, 1996, in support of NARUC's request for rehearing on the jurisdictional issues pertaining to the recovery of retail stranded costs. While answers to requests for rehearing generally are not permitted, 18 CFR 385.213(a)(2) (1996), we will depart from our general rule because of the significant nature of this proceeding and will accept these comments.

[700] According to NASUCA, whether or not that authority includes a requirement that a utility receive 100 percent return on stranded costs (or something less) is a matter to be determined by the state courts and legislatures.

[701] *See also* AR Com (one retail transaction is replaced by another retail transaction; there is no wholesale transaction and no wholesale costs over which the Commission has jurisdiction).

[702] *E.g.*, NARUC, Central Illinois Light, IN Com, American Forest & Paper, IN Consumer Counselor, IN Consumers, IL Com.

[703] *E.g.*, Central Illinois Light, IN Com, American Forest & Paper, IN Consumer Counselor, IN Consumers, IL Com. TX Com considers that it has the power to address stranded cost issues related to retail transmission service.

[704] IL Com at 38 (emphasis in original).

of the regulatory agency, but not that of the legislature.

AMP-Ohio and Cleveland ask the Commission to clarify that its deference to the determinations of the states is to the authority of the states as exercised through state legislative bodies (and other political subdivisions with legislative authority) as well as to state regulatory bodies. They submit that if the state legislature, or a local government acting in accordance with its authority, enacts retail wheeling legislation that expressly limits the ability of its regulatory body to permit recovery of stranded costs, even barring all such recovery, the Commission should not become involved.

Several entities ask the Commission to clarify that Order No. 888 does not permit utilities to apply to the Commission for recovery of stranded costs associated with a retail wheeling customer when a state regulatory authority has ''addressed'' a request for the same stranded costs but has not allowed 100 percent recovery.[705] ELCON gives two hypothetical examples to which it asks the Commission to respond: one where a state regulatory authority possesses full stranded cost recovery authority but allows only 50 percent recovery; the other where the state legislature provides the state regulatory authority by statute with the power to permit recovery of up to 50 percent of identified stranded costs.

Commission Conclusion

We reaffirm our conclusion that both this Commission and the states have the legal authority to address stranded costs that result when retail customers obtain retail wheeling in interstate commerce from public utilities in order to reach a different generation supplier, but that, because it is a state decision to permit or require the retail wheeling that causes retail stranded costs to occur, we will leave it to state regulatory authorities to deal with any stranded costs occasioned by retail wheeling. The only circumstance in which we will entertain requests to recover stranded costs caused by retail wheeling is when the state regulatory authority does not have authority under state law to address stranded costs when the retail wheeling is required.

We will reject the requests for rehearing that oppose any Commission involvement in stranded costs associated with retail wheeling customers. We disagree with those entities that challenge our conclusion that both this Commission and the states have the legal authority to address stranded costs that result from retail wheeling (variously described by those entities as dual, concurrent, or joint jurisdiction). The Commission explained in detail in Order No. 888 the legal basis for concluding that this Commission and the state commissions each have jurisdiction over separate aspects of a retail wheeling transaction.[706] This Commission has jurisdiction over the rates, terms, and conditions of unbundled retail transmission in interstate commerce by public utilities. State commissions have jurisdiction over local distribution facilities and the service of delivering electric energy to end users. Based on our respective jurisdictions over separate aspects of the retail wheeling transaction, we believe either has the authority to provide the former supplying utility with an opportunity to recover costs stranded when the departing customer uses retail transmission in interstate commerce to reach a new supplier, but that here, unlike the retail-turned-wholesale scenario, the state commission should be the primary forum because these costs are stranded by the action of the state. We would act only if the primary forum is not available. We have made a policy decision that this Commission will step in to fill a regulatory ''gap'' that could result in no effective forum under which utilities would have an opportunity to seek recovery of prudently incurred costs.

Several entities argue that the Commission does not have jurisdiction over stranded investment in retail generating assets, that use of Commission-jurisdictional transmission does not change the character of the costs that are stranded, that stranded costs associated with retail wheeling customers are not costs of providing unbundled transmission service, but are costs associated with providing what was formerly bundled retail service, and that only state regulators are in a position to rule on the treatment of costs that were allowed in retail rates pursuant to state laws. While we agree that stranded costs associated with retail wheeling are costs that are retail in character in the sense that they are in retail bundled rates and become stranded as a result of retail wheeling required by the state commission, we do not believe this precludes the Commission from exercising jurisdiction in the limited circumstances of the Rule.

As an initial matter, we note that there are rarely separate retail and wholesale generating facilities. Retail customers and wholesale requirements customers get energy from the same facilities, each buying a ''slice of the system.'' Typically all generating assets go into both the retail and the wholesale rate bases for determining retail and wholesale rates. Rates are determined by allocating the total generating costs among customer classes. The parties confuse the issue before us to the extent they suggest that state commissions, not this Commission, have ''jurisdiction'' over certain ''costs.'' Neither the state commissions nor this Commission has exclusive jurisdiction over ''costs.'' Each regulatory authority has jurisdiction to determine ''rates'' for services subject to its jurisdiction and, in determining rates, may take into account all of the costs incurred by the utility. Under historical cost-of-service ratemaking, each regulatory authority, in exercising its respective *ratemaking* jurisdiction, reviews the *total* costs incurred by a utility to provide service and makes its separate and independent determination of what costs may be recovered through rates within its jurisdiction.[707] Generating costs continually shift between retail and wholesale rates over time.[708]

[705] *E.g.*, ELCON, NASUCA, IL Com, NY Com.

[706] *See* FERC Stats. & Regs. at 31,780–85; *mimeo* at 427–42 and Appendix G.

[707] If a utility is regulated by both this Commission and a state commission, each commission, in setting cost-of-service rates within its jurisdiction, will separately and independently determine the utility's *total* cost of providing service (also known as the utility's total revenue requirement). This will be based on the expenses incurred in providing service and a reasonable profit on the utility's assets that are used to provide the service. The commissions may differ as to what assets are appropriately included in total rate base, what other costs are appropriately included in the total cost of service, and what rate of return should be permitted. Once each regulatory authority has determined the appropriate total revenue requirement, it then will determine what portion of that total revenue requirement should be borne by the utility's wholesale customers and what share should be borne by retail customers (also called cost allocation). Each commission may also reach different conclusions on this split as well. Thus, under historical cost-based ratemaking, regulatory authorities do not carve out so-called ''wholesale costs'' that only this Commission can take into account in determining rates subject to its jurisdiction or so-called ''retail costs'' that only a state commission can take into account in determining rates subject to state jurisdiction. Additionally, this Commission and state commissions have the discretion to determine whether costs are appropriately recovered through a transmission, generation, or distribution component of a rate (also called functionalization of costs) within their respective jurisdictions.

[708] We reject arguments that stranded retail generation costs are not a cost of providing unbundled retail transmission. While such costs are not a cost of operating the physical transmission system, nevertheless, they are an economic cost incurred as a result of being required to provide retail transmission.

More importantly, both the state commission and this Commission have a responsibility to oversee the financial health of the utilities we regulate. Each has jurisdiction to make judgments about recovery of the costs of the assets in the utility's total rate base. Utilities are entitled to a regulatory forum that can adjudicate claims that they are or are not entitled to recovery of costs incurred regardless of the initial retail or wholesale ''character'' of those costs, and we believe we have the authority and obligation to fill a regulatory ''gap'' that could occur.[709]

In response to the argument that it is solely the action of the state that allows a retail customer to seek alternative sources of supply and, as a result, there is no nexus between the Commission's wholesale transmission rule and any costs that might be stranded by a state-established customer choice regime, we agree. Indeed, as we indicate in Order No. 888, we decided to leave it to state regulatory authorities to deal with any stranded costs occasioned by retail wheeling (with a limited exception) because it is a state decision to permit or require the retail wheeling in the first instance that causes retail stranded costs to occur. Our determination, as explained above, is to fill any regulatory gap that arises as a result of interstate wheeling. We believe that it is necessary for the Commission to act as a backstop in this limited instance to ensure that costs stranded as a result of retail wheeling do not go unrecovered because the state regulatory authority lacks the authority under state law to address such costs. At the same time, as we stated in Order No. 888, we believe that most states have a number of mechanisms for addressing stranded costs caused by retail wheeling. We emphasize that this Rule is not intended to preempt the exercise of any existing state authority with respect to the assessment of a stranded cost or stranded benefits charge on a retail customer that obtains retail wheeling.

In response to arguments that the Commission's decision will result in second-guessing or interfering with a state's legislative processes and decisions, we believe these arguments are premature. As a general matter, we do not expect that our decision to be a backstop will interfere with legislative decisions that specifically address stranded cost matters and the scope of the state regulatory authority's authority in determining stranded costs. If states or parties to a retail stranded cost recovery case brought before this Commission believe that a Commission decision on the issue would interfere with state legislative decisions, they should raise their arguments, and support therefore, at that time.

We clarify that Order No. 888 does not permit utilities to seek recovery from the Commission of stranded costs associated with retail wheeling customers if a state regulatory authority with authority to address retail wheeling stranded costs has in fact addressed such costs, regardless of whether the state regulatory authority has allowed full recovery, partial recovery, or no recovery.

Rehearing Requests Supporting Broader Jurisdiction Over Stranded Costs Associated With Retail Wheeling Customers

A number of entities seek rehearing of the Commission's decision not to serve as a backstop for all stranded costs associated with retail wheeling customers. Some assert that the Commission has the legal authority to address independently stranded costs that arise from retail wheeling and that the Commission cannot lawfully abdicate or delegate such authority to the states.[710] Coalition for Economic Competition submits that the Commission correctly concluded that it has jurisdiction over retail transmission rates, terms and conditions and the authority to address retail wheeling stranded costs. Thus, it argues that the Commission is without the power to make a ''policy determination'' that results in the Commission not exercising its legal authority over stranded costs associated with retail wheeling customers. It asserts that, just as the Commission recognizes that it ''cannot simply turn over its jurisdiction'' to the states to determine facilities subject to Commission jurisdiction,[711] the Commission cannot turn over its jurisdiction to establish stranded cost charges that it correctly determined it has the authority to establish. Coalition for Economic Competition argues that the Commission should adopt a stranded cost recovery policy similar to the policy the Commission has adopted with respect to the determination of state/federal jurisdiction, whereby the Commission would defer to state stranded cost determinations so long as they are consistent with the Commission's policy.

Utilities For Improved Transition argues that the Commission's authority over public utility rates for the transmission of electric power, both wholesale and retail, is plenary and exclusive. As a result, it submits that the Commission may not avoid responsibility for costs stranded by transmission of retail power.[712] Illinois Power contends that Congress did not authorize the Commission to reject jurisdictional rate filings whenever the Commission regards the state commissions as a more convenient or appropriate forum.

EEI and the Coalition for Economic Competition contend that virtually all retail stranded costs can only occur through the vehicle of Commission-jurisdictional transmission in interstate commerce. They submit that the Commission, having recognized the clear nexus between FERC-jurisdictional transmission and stranded costs in the retail-turned-wholesale context, cannot fail to recognize the same clear nexus in the retail wheeling context.

Utilities For Improved Transition says that it is legally immaterial whether stranded costs are caused by the Commission's ordering the transmission or the states' doing so; the determining factor is who has the jurisdiction to make the rates for the service, not who has the jurisdiction to order the service.

Coalition for Economic Competition and Utilities For Improved Transition contend that the Commission must consider stranded costs that arise from retail wheeling in order to satisfy its statutory obligation under the FPA to ''set just and reasonable'' rates. Coalition for Economic Competition maintains that FPA sections 201, 205 and 206 do not give the Commission the flexibility to allow stranded costs in certain jurisdictional wheeling rates (*e.g.*, wholesale wheeling and new municipalizations) but to exclude them from other jurisdictional wheeling rates (*e.g.*, retail wheeling, municipal

[709] This is not a regulatory ''gap'' in the sense that the Commission would be asserting authority over matters not within its jurisdiction. However, the Commission would be filling a regulatory ''gap'' to the extent that the utility normally would have the opportunity to seek approval from its state regulatory commission to recover costs in retail rates from a departing retail customer or to reallocate those costs to other retail customers. In circumstances where the utility does not have this opportunity because the state regulatory authority has no authority to address the issue, we may appropriately fill this regulatory ''gap'' to permit recovery from the departing customer through the retail transmission rate.

[710] *E.g.*, Utilities For Improved Transition, Coalition for Economic Competition.

[711] FERC Stats. & Regs. at 31,784; *mimeo* at 439.

[712] Utilities For Improved Transition argues that, based on Consolidated Edison Company of New York, Inc., 15 FERC ¶ 61,174 at 61,405 (1981) and other cases, the Commission has jurisdiction over the entire delivery service (rendered on both the transmission and local distribution facilities) as a transmission transaction. Utilities For Improved Transition submits that states do not have authority over rates on local distribution facilities used to complete a transmission transaction.

annexation, and bypass).[713] Utilities For Improved Transition says that the just and reasonable standard requires the Commission to backstop the states to ensure that there is full stranded cost recovery. It objects that Order No. 888's disposition of jurisdiction creates a problem of cross-class discrimination (wholesale versus retail) and inter-class discrimination (some retail versus the remainder of the retail).

Coalition for Economic Competition further argues that the Commission's failure to address all stranded costs associated with retail wheeling customers will result in an improper taking under the Constitution.[714] It also argues that the Commission is not permitted to disregard its findings in Order No. 888 which, according to Coalition for Economic Competition, ''inexorably'' lead to the conclusion that Commission action on ''all'' stranded costs (including retail wheeling, municipal annexation, and bypass stranded costs) is required.[715]

Illinois Power argues that the FPA does not authorize the Commission to discriminate among utilities based on the state of their residence, and that the Commission must allow all utilities to seek interstate rate recovery of just and reasonable retail stranded costs. Illinois Power asserts that the Rule will lead to the absurd, unduly discriminatory result that utilities located in states whose legislatures have failed to provide for stranded cost recovery will be better off than those located in states that provide for only limited stranded cost recovery. It supports use of the Commission's statutory authority to establish a uniform, national method for retail stranded cost recovery.

Coalition for Economic Competition also contends that the Commission's decision to let the states deal with retail stranded costs is arbitrary and capricious because the Commission failed to consider the arguments that stranded cost opponents will make before state commissions, such as that a state lacks jurisdiction to impose stranded cost charges or that the state imposition of such charges may be preempted or found to be an undue burden on interstate commerce. It further argues that the Commission's reliance on state jurisdiction over the service of delivering electric energy to the end user does not reflect reasoned decisionmaking. It submits that the Commission has failed to consider that the sale of electric energy may take place outside of the state into which the energy is transmitted, in which case the state commission may have no jurisdiction over either the sale or the transmission of the energy and, accordingly, no authority to consider stranded costs.

A number of entities ask the Commission to act on requests for retail stranded cost recovery when the state commission lacks authority *or* has authority to order recovery, but has declined to do so or has only allowed partial recovery.[716]

Lastly, TX Com notes that section 35.26(d) (dealing with recovery of retail stranded costs) refers only to public utilities. It suggests that the omission of a reference to transmitting utilities appears to be inadvertent and should be corrected.

Commission Conclusion

The Commission will reject the requests for rehearing of our decision not to assume a backstop role for all stranded costs associated with retail wheeling customers. We explained in Order No. 888 that commenters that describe our action as an unlawful abdication or delegation of authority misconstrue the nature of our decision to leave stranded costs associated with retail wheeling customers (with a limited exception) to state regulatory authorities.[717] We have not ''abdicated'' or ''delegated'' to state regulatory authorities our jurisdiction over the rates, terms, and conditions of retail transmission in interstate commerce; if retail transmission in interstate commerce by a public utility occurs, public utilities offering such transmission must comply with the FPA by filing proposed rate schedules under section 205.[718] Instead, we have made a policy determination that the recovery of stranded costs associated with retail wheeling customers—an issue over which either this Commission or state commissions could exercise authority by virtue of their jurisdiction over retail transmission in interstate commerce and over local distribution facilities and services, respectively—is primarily a matter of local or state concern for which the primary forum should be the state commissions. However, if the state regulatory authority does not have authority under state law to be the forum to address stranded costs when the retail wheeling is required, then we will entertain requests to recover such costs. As we explain above in response to the rehearing petitioners that oppose any Commission involvement in stranded costs associated with retail wheeling customers, we have made a policy decision that this Commission will step in to fill a regulatory ''gap'' that could result in no effective forum under which utilities would have an opportunity to seek recovery of prudently incurred costs.[719]

We disagree with Coalition for Economic Competition's argument that our findings in Order No. 888 ''inexorably'' lead to the conclusion that Commission action on ''all'' stranded costs (including retail wheeling and bypass stranded costs) is required, much less that the Commission has ignored the findings in Order No. 888. To the contrary, as we explain in Section IV.J.1, it is not the purpose of this Rule to allow utilities an opportunity to seek to recover ''all'' uneconomic costs that might be stranded when a customer leaves its utility supplier. We have fully explained our reasons for adopting an approach that, for purposes of stranded cost recovery from wholesale transmission customers, relies on the nexus between stranded costs and the use of transmission tariffs required by this Commission and, for purposes of stranded cost recovery from retail customers, recognizes state commission jurisdiction but fills potential regulatory gaps that could arise in the transition to new market structures.

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[713] EEI states that the Commission did not rebut EEI's argument that the Commission's failure to address all retail stranded costs was unduly discriminatory.

[714] In support of its argument, Coalition for Economic Competition cites Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 602 (1944); Duquesne Light Company v. Barasch, 488 U.S 299, 307–08 (1989).

[715] Coalition for Economic Competition at 14.

[716] *E.g.,* Centerior, Southern, SoCal Edison.

[717] We also explained that the case law they cite (which they refer to again in their rehearing requests) to support the proposition that an agency is not authorized to abdicate its statutory responsibility or to delegate to parties and intervenors regulatory responsibilities is factually distinguishable and inapposite. *See* FERC Stats. & Regs. at 31,825 and note 765; *mimeo* at 554–55 and note 765.

[718] The entities who argue that the Commission has abdicated or delegated its jurisdiction to the states misconstrue the Commission's jurisdiction to determine rates for unbundled transmission in interstate commerce as somehow including exclusive ''jurisdiction'' over ''costs.'' However, as discussed above, neither this Commission nor the state commissions has exclusive ''jurisdiction'' over ''costs.'' Rather, each has jurisdiction to determine ''rates'' for services subject to its jurisdiction. It is in the course of determining ''rates'' for unbundled transmission in interstate commerce that this Commission can take into account various costs incurred by a utility to provide jurisdictional service. A state commission can take those same costs into account in making its separate and independent determinations of what costs may be recovered through rates within its jurisdiction. *See* note 707, *supra,* and accompanying text.

[719] Based on these same considerations, we reject Coalition for Economic Competition's request that the Commission assume a backstop role for all stranded costs associated with retail wheeling customers but defer to state stranded cost determinations so long as they are consistent with the Commission's policy.

We disagree with those entities that contend that the Commission must consider retail stranded costs in order to satisfy our statutory obligation under the FPA to set just and reasonable rates. In determining just and reasonable rates for jurisdictional transmission service, which currently are determined on a cost basis, the Commission satisfies its statutory obligation under the FPA by allowing utilities an opportunity to recover their prudently incurred costs plus a reasonable rate of return. As we have explained above, this may include the costs of use of the physical transmission system, as well as economic costs incurred by the utility when it provides transmission service (*e.g.*, stranded costs). However, in situations in which a state regulatory authority has the authority to address recovery of retail stranded costs, there is no regulatory ''gap,'' and there is no obligation for this Commission to provide a second opportunity for recovery.[720]

We reject arguments that FPA sections 201, 205 and 206 do not give the Commission the flexibility to allow stranded costs in certain jurisdictional wheeling rates (wholesale wheeling and new municipalizations) but to exclude them from other jurisdictional wheeling rates (retail wheeling in interstate commerce and use of another utility's transmission tariff), and that this policy somehow makes rates discriminatory. Recovery of this type of cost through a transmission rate is obviously not the norm, but is necessitated by the need to deal with the transition costs associated with this Rule. As discussed in detail in the Rule, the Commission has carefully balanced the interests of utilities as well as customers in concluding that the opportunity for stranded cost recovery through transmission rates should be permitted in only two general circumstances: (1) in the case of wholesale stranded costs, where there is a direct nexus to Commission-required transmission access; and (2) in the case of retail stranded costs, where there otherwise would be a regulatory gap because a state regulatory authority lacks authority under state law to address stranded costs at the time that retail wheeling is required. We see nothing in the FPA that precludes us from exercising this flexibility and, indeed, the parties have not pointed to anything that, in our opinion, precludes us from exercising this discretion.

We reject the argument that virtually all stranded costs associated with retail wheeling customers can occur only through the vehicle of Commission-jurisdictional transmission in interstate commerce, and therefore, that the same nexus between FERC-jurisdictional transmission and stranded costs that exists in the retail-turned-wholesale context is present in the retail wheeling context. We also disagree that it is legally immaterial whether stranded costs are caused by the Commission's ordering the transmission or the states doing so, and that the determining factor is who has the jurisdiction to make the rates for the service, not who has the jurisdiction to order the service. The opportunity for stranded cost recovery set forth in this Rule is based on the causal link between stranded costs and the availability and use of the Commission-required transmission tariff. It is true that in both the retail-turned-wholesale context and the retail wheeling context there is a limited nexus between stranded costs and Commission-jurisdictional access since, in both situations, the Commission has jurisdiction over the rates, terms and conditions of the transmission service and, therefore, the authority to permit stranded cost recovery through the transmission rates. However, the causal nexus to FERC-jurisdictional transmission and stranded costs in the two contexts (retail vs. retail-turned-wholesale) is different. In the retail wheeling context, there is *no causal nexus* between stranded costs and transmission that has been *ordered by this Commission*. In the retail-turned-wholesale context, in contrast, the opportunity for a utility to seek recovery of stranded costs is grounded on the existence of a *direct causal nexus* between stranded costs and transmission that has been *ordered by this Commission*.

We will reject the rehearing petitions that ask the Commission to act on requests for stranded cost recovery associated with retail wheeling customers not only when the state commission lacks authority, but also when the state commission has authority but either has declined to use it or has only allowed partial recovery. As explained above, our decision to entertain requests to recover stranded costs caused by retail wheeling in a limited circumstance (when the state regulatory authority does not have authority under state law to address stranded costs when the retail wheeling is required) is based on our determination to fill any regulatory gap that arises in association with interstate transmission.

We will reject TX Com's request that the Commission clarify that section 35.26(d) (dealing with recovery of retail stranded costs), which refers only to public utilities, should also refer to transmitting utilities. The Commission's decision to act as a limited backstop in the case of stranded costs associated with retail wheeling customers is based on our jurisdiction under sections 205 and 206 of the FPA over the rates, terms, and conditions of retail transmission in interstate commerce. As a result, our ability to allow the recovery of such costs through a surcharge on a section 205 unbundled transmission rate is necessarily limited to public utilities.[721]

Rehearing Requests Opposing Commission Treatment of Stranded Costs Associated With Retail Wheeling Customers in Holding Company Intra-System Agreement Cases

A number of entities oppose the Commission's proposal to address on a case-by-case basis whether jurisdictional intra-system agreements may need to be amended in order to prevent inappropriate cost-shifting that could occur if one state disallows stranded cost recovery associated with retail wheeling customers. IN Com objects that the problem is not the actions of one state or another, but rather the terms of the intra-system agreement.

AR Com objects that Order No. 888 is factually in error because a state's treatment of retail stranded costs under the Entergy System Agreement cannot shift costs to other jurisdictions.[722] It submits that whenever retail load changes, whether due to retail wheeling or any other factor, responsibility ratios under Entergy's reserve equalization schedule, MSS–1, will change and costs will shift irrespective of the regulator's treatment of retail stranded costs. AR Com says that MSS–1 reveals no changes in calculations due to retail treatment of stranded costs or any other retail ratemaking; only ''excess'' capacity costs of intermediate gas- and oil-fired plant are ''shifted'' under the Entergy System Agreement. Although the Commission has the authority to amend intra-system agreements when

[720] If the state regulatory authority is the forum before which to seek recovery, the utility may make whatever arguments it wishes regarding the justness and reasonableness of its rates, as well as any unconstitutional taking arguments it may have, before the state forum. Further, it can pursue appeals of unfavorable decisions through the state court system.

[721] We note that the definition of ''retail stranded cost'' in section 35.26(b)(5) mistakenly refers to ''a public utility *or* transmitting utility'' (emphasis added). We will revise the definition to remove the reference to ''transmitting utility.''

[722] *See also* MO/KS Coms (the cost-shifting problem does not arise because of a particular state treatment of stranded costs; it arises because Entergy insists on recovering 100 percent of its costs even when some portion of the costs are not economical).

wholesale cost allocations have become unjust and unreasonable, AR Com submits that the Commission does not have jurisdiction to reach to the state level and dictate what retail ratepayers should pay to shareholders. AR Com maintains that a FERC-jurisdictional intra-system agreement extends only to sales for resale (transactions among subsidiaries), and that if a holding company believes that an intra-system agreement is unduly discriminatory as a result of a state's disallowance of costs, the holding company can propose to amend it.[723]

AR Com argues that retail stranded costs fall to state jurisdiction regardless of whether the utility is a member of an interstate holding company. AR Com says that because the costs at issue are in retail rate base, any Commission influence over their recovery could occur only through preemption, but preemption of a state disallowance from retail rate base is possible only if there is a ''trapped cost.'' AR Com submits that a disallowance of retail rate base cost cannot result in a trapped cost because there is no inconsistency between two agencies acting within their jurisdiction; the Commission has no jurisdiction to act. AR Com maintains that, unlike the Grand Gulf situation, the Commission has not mandated any Entergy generation costs into retail rate base. It further says that different state decisions regarding recovery of retail costs are not inconsistent decisions; they represent each state applying its law to its facts. According to AR Com, decisions by states leading to less than full recovery could be deemed inconsistent decisions only if there were a federal guarantee of full cost recovery of retail costs, which there is not.

AR Com and MO/KS Coms assert that the Commission's proposal for holding company situations cannot apply to future holding companies, where there is no history of joint planning justifying cost equalization, nor can it apply to future investments. They contend that this would require an assumption that the utility subsidiaries of a registered holding company have planned, and should plan, together rather than separately (*i.e.*, that interaffiliate transactions are always more efficient than nonaffiliate transactions), and that such assumption would be sound only if having the transaction occur between affiliates is inherently more efficient than having the transaction occur between an affiliate and a nonaffiliate.

Commission Conclusion

The comments raised for the most part are either premature or reflect a misunderstanding of the Commission's decision. Contrary to AR Com's argument, the Commission in Order No. 888 in no way asserted jurisdiction over state determinations of stranded costs associated with retail wheeling customers. We agree with AR Com that our jurisdiction extends only to sales for resale (and transmission in interstate commerce) and that a holding company can seek to amend an intra-system agreement if it believes the agreement is unduly discriminatory as a result of a state's disallowance of costs. However, a holding company also may seek to amend an agreement *before* any potential disallowances can occur, to keep cost-shifting from occurring. The fact is that intra-system agreements which involve wholesale sales among affiliate companies in different states could, through operation of their reserve equalization formulas, result in customers in one or more states having to indirectly bear stranded costs that are disallowed in another state, and the Commission has a responsibility to prevent inappropriate cost-shifting. Such determinations can be made only on a case-by-case basis. Again, as we stated in Order No. 888, we encourage affected state commissions to propose mutually agreeable solutions to this potential problem.

8. Evidentiary Demonstration Necessary—Reasonable Expectation Standard

In Order No. 888, the Commission concluded that a utility seeking to recover stranded costs must demonstrate that it had a reasonable expectation of continuing to serve a customer. We stated that whether a utility had a reasonable expectation of continuing to serve a customer, and for how long, will be determined on a case-by-case basis, and will depend on all of the facts and circumstances. We also determined that the existence of a notice provision in a contract would create a rebuttable presumption that the utility had no reasonable expectation of serving the customer beyond the specified period. We said that whether or not a contract contains an ''evergreen'' or other automatic renewal provision will be a factor to be considered in determining whether the presumption of no reasonable expectation is rebutted in a particular case.[724]

We also said that we would apply the reasonable expectation standard to retail-turned-wholesale customers. We explained that, before the Commission will permit a utility to recover stranded costs, the utility must demonstrate that it incurred such costs based on a reasonable expectation that the retail-turned-wholesale customer would continue to receive bundled retail service. Whether the state law awards exclusive service territories and imposes a mandatory obligation to serve would be among the factors to be considered in determining whether the reasonable expectation test is met in a particular case.[725]

We noted that Order No. 888 does not address who will bear the stranded costs caused by a departing generation customer if the Commission finds that the utility had no reasonable expectation of continuing to serve that customer. We indicated that we anticipate that, in such a case, a public utility will seek in subsequent requirements rate cases to have the costs reallocated among the remaining customers on its system. However, we stated that we were not prejudging that issue in the Rule.[726]

Rehearing Requests Opposing or Seeking Modification of the Reasonable Expectation Standard

APPA challenges the reasonable expectation standard as being too vague. It submits that the Commission has provided no guidance concerning application of the reasonable expectation standard, other than to state that it would decide the issue on a case-by-case basis. APPA objects that public utilities can exploit the uncertainty created by this standard, which will lead to costly and time-consuming litigation. IL Com supports replacing the reasonable expectation standard with a statutory, regulatory, contractual standard.

Several entities contend that there is no basis to conclude that the reasonable expectation test could ever be met. VT DPS and Valero submit that, since 1973, utilities have known that a refusal to wheel power could subject them to antitrust liability. They say that Order No. 888 ignores the breadth of NRC

[723] AR Com also objects to the Commission's description of the issue as involving not only holding companies, but also other multi-state situations. AR Com says that ''[t]he mere fact that a company's territory crosses state lines does not automatically mean that all assets serve all customers, or that all customers are required to bear the economic risk associated with all assets, or that assets that at one time were solely state-jurisdictional can somehow, by virtue of a company's decision to expand across state lines, become FERC-jurisdictional.'' AR Com at 11.

[724] FERC Stats. & Regs. at 31,831; *mimeo* at 570–72.

[725] FERC Stats. & Regs. at 31,831; *mimeo* at 572. We indicated that the same procedures would apply to retail customers that obtain retail wheeling.

[726] FERC Stats. & Regs. at 31,831; *mimeo* at 572–73.

licensing conditions. LEPA similarly argues that the reasonable expectation standard could not be met where NRC license conditions required an explicit wheeling commitment and prohibited the utility from including in the wheeling cost any amount attributable to the loss of customers due to the wheeling. It objects that delaying a decision on stranded cost recovery in such cases holds the threat of possible stranded cost charges over the heads of bulk power purchasers and thereby chills their ability to seek competitive sellers.

TAPS asserts that there should be an irrefutable presumption that no stranded costs are due from customers with pre-existing transmission rights, including customers who were the beneficiaries of NRC license conditions.[727] TAPS submits that there can be no legitimate ''reasonable expectation'' that such customers would continue to purchase power if the price was higher than the market price.

Occidental Chemical asks the Commission to clarify that a utility could have had no reasonable expectation of recovering stranded costs from customers who, prior to the issuance of the NOPR, had the opportunity to switch to an alternative electric supplier or had the option of self-generating, obtaining on-site third-party generation, or municipalizing. Occidental Chemical further argues that it defies commercial expectations to allow a utility to argue that if a contract is silent on the issue of renewal, the obligation to purchase does not expire with the termination of the contract. It submits that the Commission has not shown that it has the authority to force customers to extend purchase agreements against their will in violation of accepted commercial practice.

A number of entities submit that the Commission erred in failing to treat a notice of termination provision as conclusive evidence that the utility had no reasonable expectation of continued service.[728] Several object that the Commission has failed to explain why the presence of a notice provision does not conclusively demonstrate the lack of a reasonable expectation and *ipso facto* terminate the obligation of the customer to purchase the product.[729] APPA objects that the Commission provided no evidence that it considered comments supporting making the presumption conclusive and that it found legally sufficient reasons to reject them.

PA Munis objects that the rebuttable presumption represents an unjustified departure from the Commission's traditional policy of enforcing the express terms of notice provisions without any inquiry into the reasonable expectations of the party, provided that the agreements were negotiated in good faith and approved by the Commission.[730] PA Munis contends that wholesale requirements customers negotiated notice provisions with the knowledge that the Commission would enforce the notice provisions according to their terms, including the specific length of the term. [731] PA Munis argues that it is arbitrary and capricious to provide utilities an opportunity to seek to amend these contracts.

Several entities submit that the rebuttable presumption invites litigation and promotes uncertainty for customers.[732] APPA objects that the Commission has failed to establish the showing that it would require to overcome the presumption.

Referring to the Commission's discussion of evergreen provisions, Central Montana EC argues that it is wrong to infer from the existence of an automatic renewal provision that the parties intended that the contract might run longer than its initial term. Central Montana EC asserts that the presence of an evergreen provision infers simply that the parties agreed upon a mechanism to avoid the renegotiation of a power supply contract if, at the conclusion of its initial term, the parties were satisfied with the contract. It maintains that the parties' obligations are defined by the term and termination provisions of wholesale power contracts, and that the presence of a mechanism to avoid contract renegotiation does not alter those termination rights.

Commission Conclusion

We will reject the requests for rehearing of our decision to adopt a reasonable expectation standard to be applied on a case-by-case basis and to treat a notice provision in a contract as a rebuttable, not a conclusive, presumption of no reasonable expectation. Contrary to the claims of some entities, the Commission has explained the basis for its finding that utilities may have had an implicit obligation to serve their wholesale requirements customers and, therefore, that a utility should be given an opportunity to demonstrate that it incurred costs to provide service to a customer and that it had a reasonable expectation that it would continue to serve the customer beyond the contract termination date. The same factors that some petitioners contend establish the absence of a reasonable expectation of continued service may be offered as evidence to be considered in determining whether the reasonable expectation test is met in a particular case.

We believe that our decision to treat a notice of termination provision in a contract as creating a rebuttable presumption that the utility had no reasonable expectation of serving the customer beyond the period provided for in the notice provision is a reasonable one. It places evidentiary significance on the fact that a contract contains a notice of termination provision. Moreover, while it gives the utility an opportunity, based on the facts and circumstances of a particular case, to rebut the presumption of no reasonable expectation, it firmly places the burden of establishing reasonable expectation on the utility. Although some entities support treating notice provisions as a conclusive presumption of no reasonable expectation, as discussed below, we decline to adopt such an inflexible approach. Nevertheless, as we indicated in Order No. 888, when a utility is seeking a contract amendment to permit stranded cost recovery based on expectations beyond the stated term of the contract, we believe that the utility has a heavy burden in demonstrating that the contract ought to be modified.[733]

Contrary to the position of PA Munis, the rebuttable presumption is fully consistent with the Commission's past treatment of notice provisions. For example, the *Kentucky Utilities Company* case cited by PA Munis supports the proposition that, until a customer *exercises* a notice of

[727] AMP-Ohio submits that where transmission access and competition have existed to varying extents for decades, there should be an irrebuttable presumption of no reasonable expectation of continued service.

[728] *E.g.*, APPA, American Forest & Paper, Central Montana EC, NRECA, TDU Systems, Oglethorpe, IMPA, VT DPS, Valero, PA Munis.

[729] *E.g.*, APPA, NRECA, TDU Systems. *See also* VT DPS and Valero (by signing a contract with a termination date, the utility assumed the risk that the customer will elect to leave when the contract expires).

[730] In support of its argument, PA Munis cites Boston Edison Company, 56 FPC 3414 (1976). *See also* American Forest & Paper.

[731] Citing Kentucky Utilities Company, 23 FERC ¶ 61,317 (1983); Philadelphia Electric Company and Susquehanna Electric Company, 65 FERC ¶ 61,303 (1993).

[732] *E.g.*, NRECA, IMPA, PA Munis.

[733] FERC Stats. & Regs. at 31,665, 31,813–14; *mimeo* at 87, 522.

termination provision, the utility is under an implicit obligation to continue to serve and plan for the future needs of the customer.[734] Thus, the presence of a notice of termination provision in a contract (particularly one not yet exercised by the customer), in and of itself, may not necessarily support the conclusion that the utility could never prove that it reasonably expected to continue serving the customer beyond the notice period.[735]

In response to APPA's objection that the Commission has failed to establish the showing that it would require to overcome the presumption, we note that the Commission cannot establish such a showing upfront because whether there is sufficient evidence to rebut the presumption of no reasonable expectation will depend on the facts of each case.

We appreciate the concerns expressed by some entities that the rebuttable presumption may increase the customer's uncertainty by inviting litigation. We have carefully weighed the pros and cons of treating a notice provision as a rebuttable presumption of no reasonable expectation versus the pros and cons of treating it as a conclusive presumption of no reasonable expectation. It is true, as some entities assert, that the rebuttable presumption approach presents the potential for litigation between the parties as to whether, in a particular case, the utility can rebut the presumption. The alternative would be to treat all contracts with notice of termination provisions as conclusive evidence that the utility could have had no reasonable expectation that it would continue to serve the customer beyond the specified notice period. While the latter approach presumably would reduce the number of cases in which the issue of a utility's reasonable expectation would have to be litigated, it would do so only by prohibiting a utility from ever demonstrating that, notwithstanding the existence of a notice provision, based on the facts of a particular case, the utility reasonably expected to continue serving the customer. While we do not prejudge the likelihood of a utility being able to rebut the presumption in a particular case, we believe that it would not be in the public interest for the Commission to absolutely preclude a utility from being able to make such a showing. On this basis, we conclude that treating a notice provision as a rebuttable, rather than a conclusive, presumption that the utility did not have a reasonable expectation of continuing service to the customer is, on balance, the fairer and more equitable approach.

Central Montana EC asserts that it is wrong to infer from the existence of an automatic renewal provision that the parties intended that the contract might run longer than its initial term. However, our statement in Order No. 888 that the existence of an automatic renewal provision will be a factor to be considered in determining whether the presumption of no reasonable expectation is rebutted in a particular case makes no such inference. Whether the utility can rebut the presumption will depend on the facts of each case.

Rehearing Requests Supporting Modification of Evidentiary Standard for Retail Customers

Several entities ask the Commission to consider adopting a rebuttable presumption that utilities had a reasonable expectation of continuing to serve any retail load for which they had a public utility obligation to serve. They submit that the burden should be on the former bundled retail customer to show that the utility's service obligation was not binding and that the utility's expectation of continuing service was unfounded.[736] Florida Power Corp and Utilities For Improved Transition suggest that the only exception to such a rebuttable presumption should be for retail customers that gave notice of termination before the effective date of the Rule. EEI expresses concern that the issue may be wrongly decided on the existence (or lack) of an exclusive franchise. It states that while many states do award franchises delineating exclusive service territories, some do not, even though long-established service arrangements are in place. Puget submits that because there is a duty to serve all retail customers, Order No. 888 should provide for stranded cost recovery from all departing retail customers without application of a reasonable expectation test.

NY Com, on the other hand, opposes application of the reasonable expectation standard to stranded costs associated with retail-turned-wholesale customers. It argues that the reasonable expectation test would ignore prudence, customer impact, financial viability and a series of criteria traditionally analyzed by state regulatory agencies in determining rate treatment of costs incurred with the intention of providing service.

Commission Conclusion

We will deny the requests for rehearing of the Commission's decision to apply the reasonable expectation standard to retail-turned-wholesale and retail wheeling customers on a case-by-case basis without adopting a rebuttable presumption that utilities had a reasonable expectation of continuing to serve any retail load for which they had a public utility obligation to serve. When a utility seeks to recover stranded costs from former bundled retail customers, we think it is appropriate that the utility bear the burden of proving reasonable expectation (instead of requiring the customer to bear the burden of disproving the utility's reasonable expectation). Placing the burden on the utility is consistent with the requirement of sections 205 and 206 of the FPA that a public utility demonstrate the justness and reasonableness of its proposed rates. The same factors that are offered as support for the establishment of a rebuttable presumption of a reasonable expectation (such as the utility's obligation to serve all retail customers) may be offered by the utility as evidence to be considered in determining whether the reasonable expectation test is met in a particular case.

We also will deny NY Com's request that the Commission not apply the reasonable expectation standard to retail-turned-wholesale customers. We believe it is appropriate to require the same evidentiary demonstration for recovery of stranded costs from a retail-turned-wholesale customer as that required in the case of a wholesale requirements customer. Moreover, as discussed in Section IV.J.7 above, the reasonable expectation standard contemplates evidence as to what a utility might reasonably expect to recover under state law, and we will give great weight to a state's view of what might be recoverable.

9. Calculation of Recoverable Stranded Costs

In Order No. 888, the Commission considered various proposals regarding how stranded costs should be calculated and who should pay. With respect to the calculation of stranded costs, the Commission rejected as overly complicated and costly an asset-by-asset

[734] *See* Kentucky Utilities Company, 23 FERC at 61,679–80 (''Once it receives an effective notice of cancellation, Kentucky can stop planning for the future needs of that customer. . . . To be effective a notice of cancellation must contain a specification of the source of supply, the date on which the source of supply will be available, and an affidavit from the supplier that it will supply the customer on the date the contract ends.'').

[735] *See* Potomac Electric Power Company, 43 FERC ¶ 61,189 (1988) (suspending a notice of termination for five months due to questions about the impact of the proposed cancellation on service reliability).

[736] *E.g.*, EEI, Oklahoma G&E, Southern, Florida Power Corp, Utilities For Improved Transition.

approach to determine the amount of stranded costs assigned to a departing customer. Instead, the Commission determined that the revenues lost approach was the fairest and most efficient way to make this determination during the transition to a competitive wholesale bulk power market. The Commission adopted the following revenues lost formula for calculating the stranded cost for each departing customer: SCO − (RSE—CMVE)×L. The Commission provided a precise definition for each component of the formula,[737] and made the application of the formula, and collection of the resulting stranded costs, subject to a number of conditions.[738]

RSE Issues

Numerous petitioners oppose the use of present revenues in the stranded cost formula.[739] TDU Systems argues that the revenues lost approach is arbitrary and capricious because its effect exceeds its purpose. Specifically, TDU Systems contends that the revenues lost approach can permit overrecovery because it provides recovery of any difference between pre-Order No. 888 cost-plus rates and post-Order No. 888 competitive rates, regardless of the cause of the difference. TDU Systems cites enhanced utilization and technological improvements as two examples of pre-and post-Order No. 888 rate differences that are not competition related, but for which recovery would be provided. TDU Systems states that instead of using present revenues, RSE should be calculated based on the most current, reliable estimate of future revenues.

Multiple Intervenors argues that the revenues lost method assumes that a utility's costs of operating its plants are *per se* reasonable, yet the New York utilities' current rates include levels of O&M, especially wages and benefits, expenses that may reflect inefficiencies and thus are not stranded costs for which a utility's shareholders should be compensated. Similarly, other petitioners oppose as backward-looking the use of present revenues for what should be a forward-looking remedy, consistent with the other elements in the formula.[740] TDU Systems argues that the use of past revenues is inappropriate in a falling cost environment, and notes that new capacity costs are less than the existing capacity costs embedded in a utility's rate base.

NYSEG states that the Commission should permit a utility to reconcile initial stranded cost charges to actual stranded costs on a periodic basis to account for changes in sales, energy purchases from NUGs, and changes in market price. NYSEG supports development of stranded cost charges based on three-year estimates. Under this approach, a customer would pay locked-in charges for a series of three-year periods. At the end of each period, the stranded cost estimate would be revised for the next three-year period. This process would continue until all stranded costs are recovered.[741] Other petitioners support the use of a projected revenue stream or a true-up mechanism.[742] These petitioners argue that a true-up mechanism is necessary to protect all parties against the inevitable risk of inaccurate forecasts.

ELCON argues that calculating RSE based upon customer usage over the past three years results in an artificially high stranded cost because it fails to take into account that the utility would have had to reduce its prices in the future in response to competition. ELCON states that wholesale customers have a reasonable expectation that utility costs will be lower in the future, and thus that the annual revenues contributed by a customer who remains with the utility would be lower than RSE. ELCON further contends that the revenues lost formula should not guarantee the profits the utility was allowed to receive prior to the issuance of Order No. 888 because such revenues included a risk factor (*e.g.*, plant operating risk, or risk of customer insolvency) that is absent under the direct assignment method of allocating stranded costs. ELCON cites *Town of Norwood* v. FERC [743] as support for its position that the RSE should be reduced to reflect the decreased risk associated with the direct assignment approach.

TDU Systems and NRECA also argue that the Commission should eliminate from RSE the risk component of the return on equity contained in present rates. They argue for this adjustment because the Commission is eliminating the risk associated with non-recovery of plant costs by providing full recovery of stranded costs. NRECA further contends that if the Commission keeps the equity return in the calculation of stranded costs, it should permit a consumer-owned system to include an imputed equity component in its RSE if it needs to recover stranded costs.

APPA argues that the use of present revenues fails to reflect future cost reductions expected from accumulated depreciation, load growth, and declining capital costs. APPA further opposes the use of present revenues because present revenues are the direct product of the monopoly power that the utility exercised over transmission. APPA states that RSE should be calculated based upon the price of wholesale power in a competitive market.

CCEM argues that only fixed costs should be eligible for recovery, and that this amount should exclude any return on investment. CCEM would exclude variable costs from the calculation of stranded costs because allowing recovery of variable charges would encourage the continued operation of facilities that are conceded to be uneconomic. CCEM further contends that the Commission should provide less than full recovery of stranded costs so that the utility has some incentive to mitigate them.

Central Vermont states that where the contract does not commit the customer to a set amount of service, the utility's reasonable expectation of the amount of continuing service will not necessarily be reflected in the revenues of the three previous years. Central Vermont urges the Commission to allow utilities the option of showing that their actual reasonable expectation of continued service differs from historical experience. Central Vermont maintains that any other approach would be less than reasonable, and, in fact, would be arbitrary and capricious.

Numerous petitioners [744] would retain the use of present revenues as the RSE; however, they support a limited exception that would permit a utility to seek recovery of certain future cost increases (primarily nuclear decommissioning costs, back-loaded PURPA contract costs, and other deferred costs) if those costs are not in rates now or are in rates but are being under-recovered at present. These

[737] Briefly, SCO refers to the departing customer's stranded cost obligation, which is determined by taking the average annual revenues that the customer would have paid had it remained a customer of the utility (RSE), and subtracting from it the competitive market value of the power (on an average annual basis) no longer taken by the departing customer (CMVE). The difference represents the average annual stranded cost, which must be multiplied by ''L'' (L represents the period over which the utility reasonably could have expected to serve the departing customer beyond the contract termination, but for the open access required under Order No. 888) to produce the departing customer's total SCO.

[738] FERC Stats. & Regs. at 31,839–40; *mimeo* at 595–99.

[739] *E.g.*, TDU Systems, APPA, Central Vermont, ELCON.

[740] *E.g.*, TDU Systems, NRECA, Central Montana EC, SoCal Edison.

[741] *See also* Coalition for Economic Competition at 47.

[742] *E.g.*, Central Vermont, Texaco, Carolina P&L.

[743] 80 F.3d 526 (D.C. Cir. 1996) (*Town of Norwood*).

[744] *E.g.*, EEI, Utilities For Improved Transition, VEPCO, Coalition for Economic Competition.

petitioners argue that the majority of these costs were incurred as a result of various regulatory mandates, with the reasonable expectation of future recovery in rates. As a part of their proposal, Utilities For Improved Transition and EEI (and others) support offsetting such cost increases with any decreases in other costs reflected in present revenues. Utilities For Improved Transition maintains that nuclear decommissioning costs, in particular, should be revisited as they become better defined. Similarly, Nuclear Energy Institute and others request that the Commission allow a utility, on a case-by-case basis, to propose its own recovery mechanism, as nuclear decommissioning costs are significantly different from other future cost increases.

Lastly, TDU Systems and NRECA object to the manner by which the formula deducts average transmission-related revenues (which would be unbundled in the utility's new open access tariff) in the development of RSE. TDU Systems and NRECA contend that the transmission credit, because it is based on the revenues that would be generated under a utility's new wholesale tariff, would not reflect that the cost of transmission has been declining.

Commission Conclusion

In Order No. 888, the Commission stated that the use of ''present'' annual revenues as the basis for the stranded cost calculation has numerous advantages over other approaches advocated. The Commission noted that the use of present revenues (1) eliminates disputes over estimates of future revenues, providing certainty to the calculation; and (2) eliminates the need for a detailed listing and litigation of includable costs, relying instead on the presumption that present rates include all just and reasonable costs of providing service. The Commission further noted that the rates that produce present revenues have been approved by regulators, which strongly suggests that the costs included in them are prudent, legitimate and verifiable.

The Commission continues to believe that the use of present revenues as the basis for the stranded cost calculation is superior to other proposed methods. Arguments that the use of present revenues either over-or under-recovers ''true'' costs are not persuasive. Either the customer or the utility may file for a change in rates before the existing contract ends if it believes the existing rate is inappropriate.

In response to petitioners requesting an RSE based on estimates of future revenues for the reasonable expectation period (L), we continue to believe that an approach based on estimates of future revenue streams would engender countless disputes over the RSE component in the formula with little, if any, added accuracy. These would in effect be rate cases that attempt to litigate not what costs were during a test year based on audited accounting data, but what costs will be, based on speculation about future fuel costs, employment levels, capital costs, and so on. In contrast, we believe that the use of present revenues will produce fair results and minimize litigation of RSE. This is appropriate for a transition period cost recovery charge that needs to be settled quickly for market participants to make business decisions about future wholesale sales and purchases. Our approach minimizes transaction costs and provides greater certainty with respect to the RSE term in the formula.

Some have argued that a method that periodically adjusts the departing customer's stranded cost obligation in the future to reflect actual future increases or decreases in a utility's future cost-based rates would produce more accurate results. However, this ''true-up'' approach has several difficulties. First, it assumes that the utility will have wholesale cost-based rates in the future. Many utilities already sell in the wholesale market at market-based rates, and this trend is accelerating. Having a series of ongoing rate cases solely for the purpose of trueing-up a stranded cost calculation would be cumbersome and costly. It would eliminate much of the regulatory cost savings that result from market-based rates. Further, even if ''cost-based'' rates were on file in the future, many such future wholesale rates, as in the past, are likely to result from settlements among the parties. Such settlements are agreements on prices that do not necessarily spell out the cost components of the final agreed-upon rate.

These difficulties aside, the true-up approach would introduce a great deal of ongoing uncertainty about the departing customer's stranded cost obligation. This uncertainty would add unnecessary risk for both the customer and the utility as they consider alternative purchase or sales transactions. Customers would have no way of knowing what their ultimate stranded cost charge would be, and therefore would be unable to evaluate definitively whether changing suppliers would be beneficial. Under a true-up approach, the eventual sum of the customer's SCO and replacement power cost could be more or less than the amount it would have paid had it simply stayed with its host supplier. This possibility could discourage many customers from taking advantage of the open access provided by Order No. 888. We believe that any potential accuracy benefit of a true-up approach is greatly outweighed by the cost, uncertainty, delay, and litigation such an approach would cause.

In summary, we believe that the use of present revenues as the basis for calculating stranded cost appropriately balances precision and efficiency [745] for what is fundamentally a transition period policy.

In response to the other arguments raised, the Commission makes the following findings. We disagree with ELCON that the use of present revenues will result in an artificially high stranded cost because it fails to account for the fact that a utility would have to lower its prices to respond to new competition. ELCON's argument is circular in that much of the new competition to which it refers results from our issuance of Order No. 888. ELCON's approach would undo the goal of providing recovery of stranded costs by eliminating the very difference that the formula is intended to determine. [746] ELCON's argument is rejected accordingly.

In addition, ELCON's reliance on *Town of Norwood* (for the proposition that RSE should be reduced to reflect the reduced operating risk and reduced risk of customer insolvency associated with direct assignment of stranded costs) is misplaced. In *Town of Norwood*, the Commission was faced with a request for recovery of plant costs. The utility made a cost-effective proposal to shut down its single asset, a small nuclear reactor. In that case, the Commission disallowed full return on investment in part because the unit was no longer operating and the utility had no operating risk.

Elimination of the rate of return is inappropriate because, unlike *Town of Norwood*, the departing customer's service is not tied to any particular unit; rather, service is considered to be provided by the entire system. Contrary to ELCON's assertion, operating risk is not reduced because the utility must continue to operate its generating facilities (by reselling the capacity) if it is to recover all its costs. Accordingly,

[745] The use of present revenues is reasonably workable from an administrative standpoint.

[746] Our rationale here is equally applicable to APPA's argument that RSE should be based upon the price of wholesale power in a competitive market.

there is not a reduced operating risk as argued by ELCON.

With respect to ELCON's customer insolvency argument, this risk is also present under the direct assignment approach. Because Order No. 888 permits a customer to pay its stranded cost obligation over a number of years, during this period the customer could become insolvent, thereby leaving the utility with uncollected stranded costs.[747]

Also, unlike *Town of Norwood,* the utility is presently collecting rates that compensate for traditional utility risks, but do not include the risk of open access. Further, eliminating the rate of return would engender considerable complication, speculation and expense as the Commission would have to determine an appropriate rate of return that included some risks (*e.g.,* customer bankruptcy) but not others (*e.g.,* 211 request or use of the open access tariff). Thus, eliminating the rate of return (or a portion thereof) is inappropriate.

Accordingly, ELCON's arguments that the revenue stream should be reduced to reflect lower risk associated with direct assignment is rejected. Instead, we continue to believe that the transmission provider is entitled to recover all the costs, including return on equity, that it incurred based on a reasonable expectation of having to serve the departing customer. All these costs would have been recoverable absent the action taken in Order No. 888.[748]

The Commission also rejects NRECA's proposal to include an imputed equity component in the RSE when calculating stranded costs for a consumer-owned system. Simply put, if a cost is not stranded, or if a cost is not really a cost, recovery should not be granted.

The Commission rejects APPA's contention that it is inappropriate to use present revenues as the RSE because those revenues are the direct product of the monopoly power that the utility exercised over transmission. The Commission believes that the use of present revenues is one of the strengths of the formula in that the rates that produce present revenues have been approved by regulators as just and reasonable, which strongly suggests that the costs included in them have been shown to be prudent, legitimate and verifiable.

In response to CCEM's argument that only fixed costs should be eligible for recovery (because the inclusion of variable costs in the RSE will encourage the continued operation of facilities that are conceded to be uneconomic), we agree. The Commission notes that condition 1, ''Cap on SCO'' [749] limits the recovery of stranded costs to fixed costs. Accordingly, the formula, as designed, addresses CCEM's concern.

We note that Central Vermont supports its opposition to the use of present revenues differently from other petitioners, who argue (in effect) that the price component of RSE is flawed.[750] Central Vermont, on the other hand, is concerned that the quantity component of present revenues may not reflect the quantity that would have been taken during L. It states that the Commission should permit the utility to show that it had a reasonable expectation of continued customer service that is not based on the customer's previous three years of power consumption. The Commission does not believe that this is appropriate. Central Vermont's approach would introduce forecasting controversy, litigation cost, and uncertainty which are similar to the disputes about cost discussed above. For example, a utility might argue that the customer was expected to consume more than it has in the last three years, based presumably on such factors as expected economic development, changing demographics, appliance saturation rates, and even changes in climate. Conversely, the departing customer might argue that it would have increased electricity conservation efforts, used more natural gas, relied more on self-generation, and so on, if open access had not been made available by Order No. 888. The Commission has stated above why it favors the use of present revenues, for both price and quantity combined, and these reasons apply regardless of whether the argument is directed toward the price or quantity component of present revenues.

Finally, TDU Systems' and NRECA's argument regarding the transmission revenue credit component of RSE is made on the same basis as their argument that the revenue stream should be calculated on a forward-looking basis. For the reasons discussed above, we reject this argument also.

Therefore, after consideration of the arguments on rehearing, and reconsideration of our policy rationale supporting the use of present revenues, we continue to support the use of present revenues, without true-ups or adders, as the basis for the stranded cost formula. We find that the use of present revenues fairly and efficiently balances the competing interests of the affected parties.

CMVE Issues

Petitioners raised a number of CMVE related issues. We take them up in the following two categories.

Present Value Issues

EEI agrees with the Commission that stranded costs should be calculated on a present value basis. EEI states that with respect to RSE, the formula appears to be stated on a present value basis, although it believes that the language could be strengthened to read: ''*the present value of* average annual revenues from the departing customer over the three years prior * * *'' (new text *emphasized*).

However, EEI maintains that the rule fails to define CMVE clearly on a present value basis. Therefore, EEI suggests that the Commission clarify the definition as follows: ''Option 1—the utility's estimate *of the net present value of* the average annual revenues * * * or Option 2—*the net present value of* the average annual cost to the customer of replacement capacity and associated energy * * *'' (new text *underlined*). EEI states that this clarification could also be applied to the ''Cap on SCO,'' to put it on a par with the other definitions in terms of the time value component.

TDU Systems and NRECA also express concerns regarding the calculation of SCO on a present value basis. Specifically, they state that the formula contains no component, factor, or other mechanism to indicate how such present value is to be determined. They also state that no discount rate is specified, and that the calculation should be synchronized with the customer's chosen payment option. Central Vermont maintains that the Commission should make it clear that a utility is entitled to recovery of both

[747] In addition, Order No. 888 provides recovery of only the difference between the average annual revenues that the customer would have paid had it remained a customer (RSE) and the estimated competitive market value (CMVE) of the released power (*i.e.,* the stranded cost). However, while the formula contemplates that the utility can sell the released power at the estimated competitive market value, the actual market value may be lower, increasing the risk that the utility will not be able to recover its stranded costs.

[748] In Order No. 888, the Commission rejected arguments that return-related revenues be excluded from the revenue stream. The Commission found that such exclusion would effectively require shareholders to absorb stranded costs, which is contrary to the Commission's finding that a utility is entitled to an opportunity to fully recover legitimate, prudent and verifiable stranded costs. In this order, we reaffirm our earlier finding.

[749] FERC Stats. & Regs. at 31,840; *mimeo* at 597.

[750] Present revenues depend, of course, on both price and quantity. Most petitioners who dispute the use of present revenues argue, in some fashion or another, that present revenues are inappropriate because the costs included in present revenues may not equate to the costs incurred by the utility during L. These petitioners are arguing about price.

stranded costs and the time value of those costs from the date on which they were experienced through the date of their recovery.

Commission Conclusion

We believe that EEI misinterprets our intent with the three-year average annual revenues for RSE. EEI is proposing to increase the revenues of three years ago to current dollars, the revenues of two years ago to current dollars (and so on) before finding the three-year average. The Commission clarifies that our use of the term ''present value'' does not require such an adjustment. If the utility thought its rates on file did not adequately reflect rising costs, it should have filed for a rate increase. If it did file for and receive a rate increase, the formula does not use a three-year average, but rather revenue based on the new rate.[751] It would be inappropriate to adjust the three years of revenue used to calculate RSE to a current dollar value if these rates have been in effect for three years without change. It is assumed that all costs, including inflationary and deflationary changes in the underlying costs, have been recovered. We do not have any time lag between the provision of service and the recovery of the costs of providing that service. Accordingly, EEI's proposed present value adjustment is neither necessary nor appropriate.

With respect to EEI's concern that CMVE is not determined on a present value basis, we clarify that it should be calculated on a present value basis. Both the revenues that would have been collected if the customer had remained on the system and the revenues the utility expects to collect by selling the power must be stated on a present value basis so that the difference, RSE–CMVE, is at present value.[752] The ''Cap on SCO'' must also be stated on a present value basis.

In response to TDU Systems, NRECA and Central Vermont, we clarify that a utility is entitled to recovery of stranded costs and the time-value of the revenues that would have been recovered.[753] However, we decline to specify the discount rate or the number of periods to be used in the calculation. Although establishing a uniform discount rate would serve to minimize disputes over the calculation, we prefer to give the parties some flexibility on the use of a discount rate. Similarly, we do not prescribe the number of periods to be used in the present value calculation as this also should be determined on a case-by-case basis due to differences in ''L'' and billing payment cycles for each departing customer.

CMVE Option 2 Issues

In Order No. 888, the Commission allows the departing customer to set CMVE equal to the average annual revenues it would pay to its alternative supplier. This option is referred to as CMVE Option 2.

SoCal Edison and Central Vermont argue that CMVE Option 2 should be eliminated because it will be administratively difficult to monitor and enforce. In their view, Option 2 will allow customers the opportunity to ''game'' the system, which will increase the utility's and the Commission's administrative costs and place the utility at risk for less than full recovery of stranded costs. In addition, SoCal Edison maintains that it will be difficult to reflect in the calculation of stranded costs any non-price benefits a customer may receive under the contract. SoCal Edison further maintains that there is a possibility that additional bargains may have been struck outside of the agreement between the new supplier and the departing customer. These bargains may have the effect of increasing the price of the alternative power, but the terms of the bargains would not be known to the utility to use in adjusting CMVE. As a result, the customer's contract price may not accurately reflect the utility's CMVE, resulting in an inaccurate estimate of stranded cost responsibility.

EEI has requested that the Commission clarify that the conditions placed on CMVE Option 2 were intended to prevent the customer from unfairly avoiding its full stranded cost obligation (*i.e.*, prevent gaming of the stranded cost calculation). EEI also states that the Commission should give the utility an opportunity to challenge the validity of the replacement contract's price, terms and conditions on a case-by-case basis or give the utility the right of first refusal to provide power to the customer under the replacement contract's price, terms and conditions. Carolina P&L requests that the Commission require the departing customer to make a compliance filing containing information regarding the replacement contract. Centerior maintains that in order to guard against the customer overpaying for replacement capacity (thereby lowering its SCO), the Commission should use the revenues received by the host utility in the resale of the power to determine the CMVE.

NRECA and TDU Systems maintain that the formula fails to address how the CMVE component will be adjusted when the customer's contractual commitment for replacement capacity is for a period shorter than L.

Commission Conclusion

The comments filed in response to our Open Access NOPR maintained overwhelmingly that determining accurately the competitive market value of the released capacity and energy is a difficult and subjective task. Therefore, we did not prescribe a CMVE by formula as we did for RSE. Instead, we provide options for determining it. Our requirement for the utility to estimate it is CMVE Option 1. However, the customer may contend that the utility will underestimate CMVE under this option so as to increase the customer's stranded cost obligation. In response to these concerns, the Commission adopted CMVE Option 2 because ''[t]he customer will test the market and choose the best deal available. Hence, the price the customer pays its alternative supplier is arguably a more accurate measure of the competitive market value of the capacity and associated energy not taken from the host utility.'' [754] The Commission also believes that, because of the potential for disputes over the CMVE component of the formula, many utilities and departing customers would appreciate CMVE Option 2 because it would provide them with a simple and reliable method for determining the CMVE.

However, the Commission recognized the potential for gaming on the part of the customer. To address this potential, the Commission placed certain conditions on the use of Option 2. One of these conditions is that the departing customer must demonstrate that the replacement service is equivalent to that from the current supplier. This provides the utility with the ability to investigate whether the new service is essentially the same, in terms of contract duration, terms and conditions, as that which it currently provides the customer. Any unresolvable disputes over the value of

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[751] Condition 2 requires use of the most recent twelve months of revenue if there has been a rate change. *See* FERC Stats. & Regs. at 31,840; *mimeo* at 597.

[752] If RSE and CMVE are calculated on a present value basis, and the difference between the two is multiplied by L, the result constitutes the customer's SCO. This present value is the amount to be paid under the lump-sum payment option. If the customer chooses another payment option, additional time-value calculations would be required to match the customer's stranded cost obligation with a series of payments made over time.

[753] The utility is entitled to recover no more than the present value of the revenue stream (less the competitive market value) it would have received had the customer remained on its system.

[754] FERC Stats. & Regs. at 31,842; *mimeo* at 604.

non-price benefits contained in the customer's replacement contract, which is SoCal Edison's concern, can be developed during a stranded cost hearing, and the Commission will decide the disputed issues based on the record provided. SoCal Edison's concern with additional bargains outside the contract, which increase the contract price and lower the customer's SCO, is properly addressed through the discovery process. The utility could ask for a copy of agreements between the new supplier and the departing customer, and the customer would be obligated to provide the requested information.

Although we recognize that there may be difficulties in assuring the ''equivalence'' of the customer's replacement contract, we believe that CMVE Option 2 creates an incentive for the utility to estimate CMVE as accurately as possible (in Option 1), and provides a quick and simple alternative to protracted litigation of the utility's estimate of CMVE. Accordingly, SoCal Edison's and Central Vermont's request for elimination of CMVE Option 2 is rejected. Also, because a utility is permitted to undertake discovery regarding the terms and conditions of the replacement contract, and any contracts or considerations associated with the replacement contract, we do not believe that it is necessary to give the utility the right of first refusal to supply the departing customer under the replacement contract's price, terms and conditions. EEI's ''gaming'' concerns are best addressed through the discovery process in a stranded cost hearing.

Furthermore, we will not require the departing customer to make a compliance filing containing information about its replacement contract, as the utility can obtain this information through discovery if it is needed and relevant, without automatically burdening the Commission with additional filings or requiring the customer to disclose confidential and irrelevant information. A customer must file replacement contract information only if it chooses to assert that the replacement contract price is relevant to the determination of CMVE.[755]

In response to NRECA and TDU Systems, the Commission reiterates that a customer cannot avail itself of CMVE Option 2 if its replacement contract is for a period shorter than L. This restriction is necessary to ensure equivalence of service.

Marketing/Brokering Option Issues

In Order No. 888, the Commission allows the departing customer to market or broker the capacity that it would strand as a result of its decision to purchase power from an alternative supplier. This option is intended to protect a departing customer from a low utility estimate of CMVE, which would result in a higher stranded cost charge to the customer.

ELCON maintains that the option to broker the released power in response to a ''low balling'' of the CMVE by a utility places an unfair burden on the customer by requiring it to engage in brokering.

SoCal Edison and NIMO argue that a customer choosing the marketing option should pay the utility's estimate of the market value of energy, rather than the average system energy costs for the energy it purchases. SoCal Edison and NIMO argue that the use of average system energy costs is inconsistent with the use of estimated market value used to calculate the customer's stranded cost responsibility and will result in an under-recovery of stranded costs. Florida Power Corp is also concerned that the payment provisions of the marketing option could result in under-recovery of stranded costs. Specifically, Florida Power Corp states that permitting customers to purchase the associated energy at average system variable costs is appropriate if the stranded capacity marketed by the customer is slice-of-system and if the energy used is at the same load factor as the average load factor of the utility's remaining requirements customers. If these conditions are not met, Florida Power Corp states that under-recovery or over-recovery of stranded costs could occur. To prevent this, Florida Power Corp would require the customer to reimburse the utility for the marketed energy at the utility's actual hourly average energy costs for the hours in which the energy is resold.

Occidental Chemical requests guidance as to when a stranded cost is ''legitimate'' and how the utility will develop an estimate of the capacity to be released. Occidental Chemical also requests clarification regarding the obligations of a departing customer to the replacement buyer and whether the departing customer can resell the capacity under terms and conditions different from those under which it bought it. Similarly, CCEM requests that the Commission clarify that there can be no conditions attached to the former customer's use of the capacity, except for conditions pertaining to safety and reliability. CCEM also contends that the 60-day limit for finding a buyer under the brokering option is too short and should be eliminated. CCEM states that if the customer pays for the capacity in the stranded cost charge, it should have flexibility in disposing of it.

Commission Conclusion

The Commission disagrees with ELCON that the brokering option places an unfair burden on the departing customer. The Commission believes that the marketing/brokering option is another effective incentive for a utility to make a good faith estimate of CMVE. Furthermore, we note that the marketing/brokering option is just that: an option. A customer is not required to exercise the marketing/brokering option, just as it is not required to exercise CMVE Option 2. Rather, the marketing/brokering option is available to a customer who believes it can reduce its stranded cost obligation through marketing or brokering the released power.[756]

In response to SoCal Edison, NIMO and Florida Power Corp, the Commission believes that permitting a customer to purchase the associated energy under the marketing option at average system variable costs is appropriate in most instances for at least two reasons. First, the capacity being marketed in all or almost all cases would not be associated with a single asset or subset of assets. Instead, a customer who chooses to exercise this option is purchasing a ''slice of the system,'' *i.e.*, a fraction of the production of all assets. Accordingly, our requirement that the customer purchase the associated energy at average system variable costs is consistent with the notion that it is purchasing a slice-of-the-system. Furthermore, we believe that the customer should have the opportunity to purchase the associated energy at the price it currently pays, and for most customers that price is based on average

[755] We note that in a section 206 proceeding initiated by a customer, Order No. 888 requires that estimates of stranded cost liability shall include the information necessary to allow the utility to understand the basis of the estimate. (Mimeo at 610 referencing Implementation Procedure (2)). The implementation requirements in Implementation Procedure (2) apply not only to a utility making a stranded cost estimate, but also to a customer filing under section 206. Therefore, in case Order No. 888 is unclear, we clarify that a customer filing under section 206 and choosing CMVE Option 2 must include a copy of its replacement contract and any other information necessary to determine the equivalence of its replacement contract.

[756] If the customer decides not to exercise either CMVE Option 2 or the marketing/brokering option, the customer still would be permitted to challenge the reasonableness of the utility's CMVE estimate (under CMVE Option 1) as well as the reasonableness of the other aspects of the utility's stranded cost estimate.

system costs. It is not appropriate to require market value pricing of associated energy when the customer's present payments are based on average system variable costs. For SoCal Edison and NIMO, we further clarify that, when the departing customer markets the released power at a market-based rate and pays average system variable cost for the energy component of the price, the difference between the market price of the power and the average system variable cost determines the market value of the released capacity. When we refer to ''purchasing energy at average system variable cost,'' we refer to compensation for the variable cost component of the sale (mostly fuel cost); we are not referring to the total price of the power sale, which would include a fixed cost recovery component.

We agree with the argument of Florida Power Corp. The Commission recognizes that there may be instances where the departing customer does not purchase energy at average system variable costs. We also recognize that the entity to which the departing customer sells the released capacity may have a usage pattern that differs significantly from that of the departing customer. In this circumstance, the utility should be paid actual hourly average energy costs for the hours in which the energy is resold by the departing customer. Parties should address this issue in their marketing agreement.

In addition, we clarify that the departing customer's capacity charge is the utility's CMVE minus average system variable costs as contained in its estimate of RSE.[757] Hence, the capacity charge is the fixed cost that the utility could recover if it sold the power at market value. This approach assumes that the customer choosing the marketing option is buying a slice of the system and buys the energy associated with the released capacity on the same basis as under its contract with the utility.

In response to Occidental Chemical, a stranded cost is legitimate if it meets the criteria established in the Rule. With respect to the obligations of a departing customer to a replacement customer, such obligations will be governed in part by the individual contracts between the parties. However, with respect to Occidental Chemical's question as to whether the departing customer can resell the capacity under terms and conditions different from those under which it bought the capacity, the Commission finds that, at a minimum, the customer is entitled to resell the capacity and energy under the terms and conditions governing its purchase from the utility. However, customers would not be precluded from negotiating different terms and conditions with the utility.

In response to CCEM's concerns, the Commission will not prohibit a utility from attaching conditions to the former customer's use of the system. There may be circumstances (which we have not contemplated) where certain conditions may be necessary, and we do not wish to foreclose such instances at this time. However, we caution utilities against using this to restrict the customer's use of this option. We reiterate our finding in Order No. 888 that the utility should allow the customer to market/broker the released capacity under terms and conditions comparable to a utility resale of the capacity to a third party.

The Commission disagrees with CCEM that the 60-day period for finding a buyer under the brokering option is too short and should be eliminated. The 60-day period protects both customers and utilities in the event that an acceptable buyer for the power cannot be found. It protects the utility from being stuck with the released capacity for an extended period, during which time it can receive only minimal compensation for it.[758] Similarly, the 60-day limit protects the customer by reverting back to the formula if its brokering attempt is unsuccessful. CCEM's argument that the customer who pays for the capacity in the stranded cost charge should have flexibility in disposing of it ignores the fact that under the brokering option (as opposed to the marketing option), the customer does not take title to the released capacity. For these reasons, the Commission continues to believe that a time limit is necessary, and that 60 days is adequate to meet the dual goals described above.

Length of Reasonable Expectation Issues

American Forest & Paper faults the Commission for failing to limit the period of reasonable expectation to a discrete period, such as three to five years. TDU Systems contends that the threat of stranded costs extends well beyond a mere transition period, and therefore, is inconsistent with the Commission's statement that stranded costs are a transition issue. TDU Systems maintains that the period of reasonable expectation should be defined as the shorter of either the term of the terminating contract or the utility's planning horizon as of July 11, 1994. IL Com states that absent a statutory, regulatory or contractual obligation to incur costs or provide service, the length of a utility's expectation to serve a customer beyond its contract expiration should be zero. However, IL Com states that if a statutory or regulatory obligation to serve can be demonstrated by a public utility on a case-by-case basis, extra-contractual recovery may be appropriate but should not exceed three years. IL Com proposes a formula for L that incorporates a three-year cap.

Commission Conclusion

We reiterate that our stranded cost procedure applies to wholesale contracts only if they are entered into on or before July 11, 1994 (and do not contain exit fees or other stranded cost provisions), so that as these contracts end this stranded cost recovery procedure will cease to apply. This fact alone shows that the policy is a transition issue and not a permanent policy for wholesale requirements contracts. Further, it should be remembered that a utility must demonstrate that it had a reasonable expectation of continued service for a time certain (L) before any stranded cost is recognized to exist or recovery permitted. This is not an insignificant demonstration. Moreover, although we decline to establish an outside limit for L, it is likely that the longer the period claimed by the utility, the harder it will be for the utility to demonstrate a reasonable expectation. In any event, to provide recovery of the full stranded cost, it is necessary that the reasonable expectation period not be limited to an arbitrary number, such as three to five years, as suggested by American Forest & Paper.

Regarding the time it takes to complete the transition to a market unaffected by stranded cost considerations, the Commission distinguishes the reasonable expectation period for determining the amount of stranded costs attributable to a departing customer from the period over which the customer pays for stranded costs. For example, a utility may have incurred a cost under the expectation that the customer would remain for another seven years (L). However, the customer could pay that amount

[757] For estimation purposes the utility should still provide its CMVE on a market value basis for both capacity (fixed) and energy (variable) so that customers can better understand the basis for the utility's estimate.

[758] This is so because, throughout the period that the customer is trying to find a buyer, the utility can sell the released capacity and energy only in the short-term market, most likely at a lower price than it could receive in a longer-term market. The utility is limited to the short-term market because the capacity must be available when the customer finds a buyer.

immediately, over three years, over seven years, or over a longer period. The period of reasonable expectation, L, is unrelated to the repayment period. If all customers were to choose the lump-sum payment option, the transition period to a market completely unaffected by stranded cost recovery would be short.

In response to TDU Systems, we note that its proposal to define the period of reasonable expectation as the shorter of either the term of the terminating contract or the utility's planning horizon as of July 11, 1994 is not foreclosed by our Rule. When faced with a claim for stranded costs, TDU Systems may argue that either of these limit the reasonable expectation period in that instance. However, it would be inappropriate to limit generically the period of reasonable expectation as suggested because the limitation may not fit all circumstances. We reiterate that whether a utility had a reasonable expectation of continued service, and for how long, will be determined on a case-by-case basis, and will depend on the facts and circumstances of each individual case.

With respect to IL Com's argument that absent a statutory, regulatory or contractual obligation to incur costs, the length of a utility's expectation to serve a customer beyond its contract expiration should be zero, the Commission agrees that such obligations are likely to be the principal reasons for a reasonable expectation in most cases, but we would not preclude a utility from introducing other relevant evidence. If a utility can demonstrate that costs were incurred to serve a customer, based on a reasonable expectation of continued service, and if that customer uses the open access provided by Order No. 888 to reach an alternative supplier, leaving the utility with unrecovered costs, the utility should be allowed to make its case for recovery of those costs based on whatever evidence it chooses to offer.

Implementation Issues

SoCal Edison is concerned that, under the framework established in Order No. 888, a customer could request numerous estimates of stranded costs based on different alternative supply scenarios and departure dates, to which the utility would have to respond in a 30-day period. SoCal Edison states that the Commission should reasonably limit the number and types of requests. SoCal Edison maintains that if the number and type of a customer's requests are unduly burdensome or unreasonable in the utility's view, the utility should be permitted to refuse the requests. Under SoCal Edison's approach, the customer would have the right to petition the Commission to demand that such studies be undertaken.

SoCal Edison also argues that the Commission should allow a utility to assess a reasonable charge to cover administrative costs associated with developing the studies required to produce estimates of stranded cost responsibility.

TDU Systems states that the 30-day period allowed for a customer to respond to a utility's notice of alleged stranded costs is too little time to perform an adequate analysis. In addition, TDU Systems and NRECA maintain that a customer should not be bound by its estimate of stranded cost obligation as filed in a petition for declaratory order or a section 205 or 206 proceeding. They contend that certain elements of the formula depend heavily on data in the public utility's possession, and that the Rule, as written, will encourage the customer to present a low-end estimate of stranded cost liability. TDU Systems and NRECA maintain that the Commission should instead require the customer to state its binding estimate at the close of the discovery period when it presumably would be in possession of the data necessary to make a realistic estimate of the stranded cost floor.

PSE&G argues that a utility should be able to begin recovering stranded costs right away, subject to refund pending the outcome of the proceeding, to eliminate any incentive a customer would have to delay proceedings so as to delay payment of stranded costs.

Commission Conclusion

Regarding SoCal Edison's concern about numerous requests for estimates of stranded costs, we do not believe that the number of requests will rise to the level of ''unduly burdensome'' or ''unreasonable'' in most instances. However, if this problem occurs, a utility can petition the Commission for relief, and we will consider each petition on a case-by-case basis.

The Commission does not agree with SoCal Edison that a utility should be permitted a special charge to cover the cost associated with providing a stranded cost estimate. Such costs are likely to be *de minimis.* Given that Order No. 888 provides an opportunity for full recovery of stranded costs, we do not believe it is appropriate for a utility to charge a customer an additional fee for asking whether it can expect a stranded cost claim.

The Commission also disagrees with TDU Systems that the 30-day customer response period is too short. No utility has argued on rehearing that the 30-day utility response to a request for an estimate is too short, and only TDU Systems argues that the 30-day customer response to the utility's estimate is too short. The 30-day period is intended to speed the negotiation process, with the goal of settling stranded costs disputes without Commission involvement. Order No. 888 requires a utility to provide an estimate of stranded cost responsibility within 30 days of the customer's request for an estimate. We do not believe it is unreasonable to require the customer to respond in like time. Accordingly, we will not modify the 30-day response requirement.

Furthermore, the Commission is unpersuaded by TDU Systems' and NRECA's argument that a customer should be bound by its estimate of stranded cost obligation only after the close of the discovery period. Order No. 888 requires the utility to provide detailed support for its stranded cost estimates, and this information should be adequate to allow the customer to develop its own estimate of any stranded cost obligation.

In response to PSE&G, we clarify that recovery of stranded cost claims filed under section 205, 206, or 211/212 will be governed by these sections and the Commission's promulgating regulations thereto.

Net Benefit Issues

EGA and IMPA argue that the revenues lost approach does not capture the net utility benefits that result from open access. EGA states that no stranded costs should be imposed on any one ''lost'' customer if the utility is a ''net winner,'' that is, where the benefits from the new competitive regime outweigh the utility's stranded costs. EGA states that the formula is unclear as to how the revenues lost approach will take into account the following three potentially beneficial effects of competition: (1) an expanded customer base as a result of enhanced transmission access; (2) reductions in the cost of purchased power, which is resold by a utility; and (3) a utility's ability to obtain higher than cost of service rates for electricity. Freedom Energy argues that the potential future benefit should be factored into the revenues lost calculation.

IMPA maintains that a mechanism should be provided for recovery of the benefits of open access, particularly if a utility does not seek stranded cost recovery. IMPA states that it is economically inefficient for consumers of generation and transmission services to pay stranded costs to those suppliers that have higher than average cost generation, while the benefits from increases in asset value are not shared with the consumers or used to pay for other utilities' stranded costs. IMPA further contends that if the customer's departure as a power customer frees up the generating capacity for remarketing through the use of the transmission system, section 212 of the FPA, as modified by the Energy Policy Act, supports recognition of such benefits in the price paid by the customer for its continued usage. Finally, IMPA maintains that if a transmission provider seeks stranded cost recovery for an asset that appears ''high cost'' due to its relative youth, the asset's future lower cost as an older unit must also be included in the calculation; otherwise the departing customer will be denied the long-term average benefit of the generating asset.

Multiple Intervenors contend that there should be consistent treatment of all assets that deviate from fair market value. For example, if a utility is allowed to recover the difference between the book value of an asset and its lower market value, then that amount should be offset by the appreciated value of any assets that have a market value higher than book value. Similarly, ELCON and Freedom Energy are concerned that the revenues lost approach may overcompensate a utility for stranded costs because it fails to account for the fact that uneconomic assets may be offset by the increased economic value of other assets in a deregulated environment.[759] Freedom Energy states that losses may occur in the short run, but in the long run the utility may be better off.

Commission Conclusion

The Commission believes that the suggestion by EGA and others that a long-run comprehensive analysis be undertaken every time a customer departs, in order to determine whether the utility would eventually be a net winner, is unworkable. Identifying the competitive market value for power during the reasonable expectation period (L) is hard enough; EGA would have us also find the market value of the power for an indefinite time after the expectation period ends. Further, attempts to define which benefits are the result of Order No. 888 would, at the very least, be unwieldy and highly subjective. The Commission's approach, on the other hand, is far less subjective and more likely to produce a reasonable result.

With respect to the specific ''potentially'' beneficial effects of competition during the period L, which EGA states should be used to offset stranded costs, the Commission finds these benefits to be questionable at best. However, if these potential benefits occur, the Rule's stranded cost approach accommodates them. For example, our clarification (*infra*) that the formula addresses load growth responds to EGA's first concern that the formula should take into account the expanded customer base that results from open access. EGA's second concern, *i.e.*, that the formula should reflect reductions in the cost of purchased power, is misplaced. If, in a future market-based pricing world, a utility can purchase power at a lower cost, it must either pass this lower cost through to customers in its cost-based rates or sell power at similarly low market-based rates to other customers. In either case, except for possible timing considerations, it is unable to profit by buying low and selling high. If a utility has such a hypothetical benefit before the customer departs, the customer may file a section 206 complaint prior to the termination of the existing contract, so that the resulting rates, reflecting the reduction in the cost of purchased power, could be used to calculate RSE. Lastly, if a utility can sell at market-based rates that are higher than cost-based rates (other than in the speculative long run), it would not qualify to recover stranded costs.

In addition, ELCON's and Freedom Energy's concern that utilities may be overcompensated under the revenues lost approach is based on a study that assumes a fully deregulated environment. There is no basis for this assumption over the next several years. Furthermore, it is highly speculative whether a particular utility will necessarily be better off in future markets as the study predicts. This is especially so because Freedom Energy's argument that future benefits should be used to offset stranded costs appears to assume a short reasonable expectation period, L. We do not find merit in Freedom Energy's suggestion that events beyond the reasonable expectation period should be factored into the stranded cost calculation.

The Commission also believes that IMPA's benefit reallocation proposal is inappropriate and unworkable. It would require a utility not requesting stranded cost recovery to share with its wholesale customers any future benefits that would accrue to it as a result of Order No. 888. Customers have purchased power from utilities at cost-based rates that have been found to be just and reasonable by this Commission. Such purchases in no way convey an ownership interest in the facilities used to provide service. The rationale for stranded cost recovery, *i.e.*, payment for investments made to serve a customer under the utility's reasonable expectation of continuing to serve, cannot be converted into what would be in effect an ownership interest with the right to receive a share of profits from future sales. Moreover, IMPA's argument assumes that utilities whose assets have a book value less than market value will be able to charge market-based rates for their capacity. This assumption is unrealistic for many utilities, and therefore cannot be relied upon as basis for a generic policy. However, even if all utilities could charge market-based rates, economic efficiency would argue strongly against such utility payments to departing customers. Specifically, there would be little or no incentive for an efficient, low cost utility to seek the best deal in the power market if the profits must be credited back to its former customers, or other utilities' customers, as IMPA suggests. Therefore, while IMPA's symmetry argument (*i.e.*, customers must pay stranded costs so equity requires utilities to pay customers any benefits that result from open access) may have surface appeal, it would serve to undo the goal of Order No. 888—that is, to promote competition and economic efficiency in bulk power markets. The Commission considered carefully the issue of symmetry in Order No. 888 and provided the appropriate utility-customer symmetry: a utility is entitled to make the case that it expected the customer to remain a customer longer than the term of the contract and the customer is entitled to make the case that the term of an existing contract should be shortened.

We also reject IMPA's argument that section 212 of the FPA requires recognition in transmission rates of any generation benefits that accrue to a utility as a result of Order No. 888. Section 212 requires the Commission to consider all costs incurred by the transmission provider in providing the service, ''including taking into account any benefits to the transmission system of providing the transmission service.'' [760] We do not interpret this to refer to the resale of a utility's generation freed-up as a result of Order No. 888.

IMPA's argument that if a transmission provider seeks stranded cost recovery for an asset that appears

[759] Freedom Energy and ELCON reference a study conducted under the aegis of the Massachusetts Attorney General to support their position that the future benefits of deregulating sales of energy and capacity will produce a net gain for utilities that is often sufficient to offset the full amount of any potential stranded costs.

[760] 16 U.S.C. § 824(a).

''high cost'' due to its relative youth, the asset's projected future lower (depreciated) cost as an older unit must also be included in the calculation, improperly focusses on an individual asset. As we explained above, the revenues lost approach is not an asset-by-asset approach, but an approach that looks at a utility's current rates which are based on all the utility's assets, including typically a mix of facilities of various ages.

Lastly, the revenues lost approach automatically includes an offset of the type described by Multiple Intervenors, ELCON and Freedom Energy. The revenue stream is based on present rates, which are based on the net book value of all of the underlying assets used to provide the service. If present rates include some assets that have a market value that exceeds net book value (for example, plants that are almost fully depreciated), the formula automatically captures the described offset because the revenue stream is based on the lower book value of the utility's assets rather than their higher market value.

Miscellaneous Formula Issues

Rehearing Requests

American Forest & Paper argues that the definition of wholesale stranded costs in section 35.26(b)(1) is overly inclusive; rather than using a gross measure of stranded costs, it believes the regulations should adopt a net measure that accounts for a utility redeploying its assets in a competitive market at market price. American Forest & Paper also maintains that the formula fails to reward efficient utilities or those that already have borne the pain of restructuring. On the contrary, it argues that the Commission's definition artificially and unjustifiably improves the competitive position of the inefficient utilities. American Forest & Paper further contends that the formula fails to allocate the risk of non-mitigation to utilities, the entities that are in the best position to mitigate such costs, but rather places the risk on customers by requiring customers to challenge the utility's CMVE.

Commission Conclusion

In response to American Forest & Paper, we note that the definition of wholesale stranded cost in section 35.26(b)(1) should not be looked at in isolation. Although that definition does not specifically mention the subtraction of the competitive market value of the released power from RSE, the revenues lost formula, which is set forth in section 35.26(c)(2)(iii), does. The formula explicitly provides that a customer's stranded cost obligation is to be calculated by subtracting the estimated competitive market value (of the released power) from the revenue stream estimate.

In response to the argument that the formula fails to reward the efficient utility that has already borne the pain of restructuring, we note that our intention in providing stranded cost recovery was not to review or reward utility business decisions that preceded this Rule. Our decision was, at bottom, based on equity for a utility that chooses to make a case to regulators for recovery of costs stranded by transmission access. Furthermore, we disagree that the definition of stranded costs artificially and unjustifiably improves the competitive position of an inefficient utility. Instead, the Commission believes that to deny stranded cost recovery would violate the pre-existing regulatory compact and would unjustifiably place certain utilities with stranded costs at a financial disadvantage.

With respect to American Forest & Paper's concern about mitigation risk, the Commission requires the utility to mitigate, or reduce, its stranded cost by reselling the released capacity at a price as high as the market allows. In addition, Order No. 888 contains several other incentives (*e.g.*, the marketing/brokering option) to protect the departing customer from paying an excessive stranded cost charge. These incentives serve to mitigate stranded costs. Regarding the customer's ''requirement'' to challenge the utility's CMVE, we view this as the customer's right to challenge the utility's stranded cost estimate, which is like its right to challenge a cost item in any rate case.

Rehearing Requests

NRECA and TDU Systems maintain that the formula fails to account for any savings or reductions in fuel costs attributable to a customer's departure. NRECA and TDU Systems contend that the utility's fuel costs will decrease equivalent to the incremental fuel costs associated with the energy not taken. They maintain that if the customer's associated revenues are based on average fuel cost energy charges, stranded costs should be offset by the reduction in average system fuel costs directly related to the incremental fuel costs savings. They argue that any stranded cost recovery mechanism should properly reflect such offsetting savings.

Commission Conclusion

The Commission disagrees with NRECA and TDU Systems that the formula fails to account for any savings or reductions in fuel costs attributable to a departing customer. The formula automatically accounts for fuel costs by assuming that the utility will be reselling the same capacity and energy to another buyer, presumably at a lower price. The lower price can be viewed as contributing less to capital cost and purchased power cost recovery, but containing the same fuel cost component. Under this approach, any decrease in fuel cost caused by no longer serving the departing customer is offset by the increased fuel cost of serving the new customer. Hence, there is no fuel costs savings to reflect.

Rehearing Requests—Divestiture

CCEM continues to support divestiture of generating assets as a precondition to a utility's authority to recover stranded costs. CCEM maintains that divestiture is the only way to obtain an accurate determination of CMVE on a net asset basis.

Commission Conclusion

The Commission disagrees that divestiture is the only way to obtain an accurate measure of CMVE and we continue to believe that mandatory asset divestiture does not need to be a requirement for stranded cost recovery. However, the Rule (Section IV.J.10) states that we are willing to consider case-specific proposals for dealing with stranded costs in the context of any voluntary restructuring proceeding instituted by an individual utility.

Rehearing Requests—Load Growth and Excess Capacity

TDU Systems and NRECA argue that the formula fails to take into account the effect of load growth on the recovering utility's revenues. They maintain that if the recovering utility is able to sell the released capacity to new or existing customers, the rationale for stranded cost recovery would be eliminated. Similarly, Arkansas Cities argues that the formula is an imperfect indicator of a utility's stranded costs because it does not explicitly take into account the role played by the utility's having (or not having) excess capacity. PA Munis maintains that as a prerequisite to stranded cost recovery, a utility should be required to prove that the customer's use of open access transmission actually resulted (or could result) in excess capacity on its system.[761]

[761] *See also* Wisconsin Municipals.

Commission Conclusion

We clarify that our stranded cost policy does take into account the effects of load growth and excess capacity. The formula is used to calculate the value of stranded costs only if the Commission determines that the utility has proved it has legitimate, prudent, and verifiable stranded costs. For example, it must pass our reasonable expectation test before the formula applies. However, costs may be stranded only if they are not fully recovered from another customer; that is, the released capacity may be either left unsold or resold at a price below full embedded cost.

The resale may be either to a new third-party customer or to remaining native load. If the released capacity is resold to a third-party customer at full embedded cost-based rates, then no costs would be stranded and the formula would not have to be used. Released capacity would also be considered ''resold'' if its cost is subsequently (and without delay) included in the rate base of the utility's retail and wholesale native load. It may be included if it is needed, in the judgment of the appropriate state or federal regulatory body, for native load growth plus reliability reserve. In this case the cost is not stranded if it is fully recovered in the cost-based rates paid by native load. If the full embedded cost rate is paid by the new purchaser for the capacity released by the departing customer, the parties may argue either that there is no stranded cost or that the formula produces a stranded cost obligation of zero because CMVE equals the embedded-cost rate that the utility charges its wholesale and retail native load customers; hence RSE equals CMVE.

In response to Arkansas Cities, if the released capacity was included in the Commission-approved cost-based rates paid by the departing customer, we presume that such capacity is not ''excess'' capacity. The departing customer's rate (which produces annual revenues, RSE) for the released capacity includes capacity that regulators have approved as needed to meet the needs of requirements customers, including capacity needed for reliability reserve. The only excess capacity issue is whether the released capacity becomes ''excess'' because of the customer's departure, that is, whether the departure strands costs because the utility cannot find a buyer for the capacity. If the released capacity is ''excess'' capacity that is excluded from subsequent native load rates because it is not needed for native load, its cost may be eligible for stranded cost recovery under the formula. Thus, contrary to the arguments made by TDU Systems, NRECA, Arkansas Cities, Pa Munis and others, the revenues lost formula does take load growth and excess capacity into account appropriately in determining the departing customer's stranded cost obligation. For this reason, we reject the arguments made by commenters that the formula is flawed.

Rehearing Requests—Tax Treatment of Nuclear Decommissioning Costs

EEI and Nuclear Energy Institute request clarification that the Commission did not intend Order No. 888 to change the IRS's tax treatment of nuclear decommissioning costs. To be tax deductible, nuclear decommissioning costs must be part of a utility's regulated cost of service. EEI and Nuclear Energy Institute seek clarification that costs included in a utility's stranded cost calculation continue to be considered by the Commission as included in the utility's cost of service.

Commission Conclusion

The requested clarification is granted. We clarify that costs included in a utility's stranded cost calculation continue to be considered by the Commission as included in the utility's cost of service.

Rehearing Requests—Application of Formula to Stranded Costs Associated With Retail-Turned-Wholesale Customers and Retail Wheeling Customers

OH Com, MO Com and KS Com maintain that the Commission's formula is inappropriate for calculating stranded costs associated with retail wheeling customers and/or retail-turned wholesale customers. They contend that the formula would be impractical to administer and would produce inaccurate results given the enormity of the calculations and assumptions involved. Suffolk County argues that the formula is flawed for retail-related stranded costs because the Commission cannot guarantee any retail rates into the future because it has no basis for even speculating about how retail rates may be changed by subsequent state action.

Commission Conclusion

With respect to stranded costs caused by retail wheeling, the Commission determined in Order No. 888 that the formula was inappropriate, and that if the Commission had to determine stranded costs associated with retail wheeling it would do so on a case-by-case basis. [762] However, the formula does work for stranded costs associated with retail-turned-wholesale customers because the newly formed municipal utility would have the resources to engage in marketing or brokering and would have a marketable product. This stands in contrast to individual retail customers, most of whom are unlikely to have the resources to engage in marketing or brokering and would have very small amounts of energy for sale. Although the calculations necessary to estimate stranded costs associated with retail-turned-wholesale customers are somewhat more involved than stranded costs associated with wholesale contracts, they are not impossible or overly burdensome. Accordingly, we affirm our finding in Order No. 888 that the formula is appropriate in the retail-turned-wholesale context.

Rehearing Requests

Allegheny Power states that stranded cost recovery should not be permitted if a utility recovers large amounts through exit fees, then uses the freed capacity to make sales in the market at anything over variable costs. Allegheny Power argues that a utility with nuclear generation, which has a low variable cost, can dump power on the market because its fixed costs are subsidized by stranded cost recovery. Allegheny Power requests that the Commission recognize that this distortion of the competitive market should not be facilitated by stranded cost recovery.

Commission Conclusion

Allegheny Power's concern that a utility recovering stranded costs will use those revenues to subsidize sales in the market at anything above variable costs is misplaced. In the power market, power pricing decisions are based on whether the utility can recover its variable cost, plus earn some contribution to capital costs. Stranded cost revenues are not relevant. This fact is demonstrated by considering the situation where no stranded cost revenues are provided to a utility with nuclear generation as described by Allegheny Power. The utility, in pricing power for off-system sales, would still face the same choice, *i.e.*, make the sale and earn some minimal contribution to capital, or forego the sale and earn nothing. The Commission's decision to provide recovery of stranded costs does not change the economics involved in utility power pricing decisions, and does not lead to the type of market distortion that concerns Allegheny Power.

[762] FERC Stats. & Regs. at 31,840; *mimeo* at 598.

Rehearing Requests

SBA asserts that determining the proper amount of stranded cost recovery is an integral step in the deregulation process.[763] It expresses concern that the revenues lost formula can be abused through the manipulation of the necessary financial statements of the parties and that such abuse could be harmful to small businesses. SBA requests that the Commission solicit its input, as well as the input of the small business community and small business organizations, when determining whether the proposed stranded cost recovery amount in a particular case is fundamentally fair in terms of maintaining a viable environment for small businesses.

Commission Conclusion

In response to SBA's request, we note that SBA, or any interested small business organization, has the opportunity to provide input to the Commission in a particular stranded cost proceeding by filing a motion to intervene in that proceeding.[764]

10. Stranded Costs in the Context of Voluntary Restructuring

No rehearing requests were filed on this issue. The Commission reaffirms that we are willing to consider case-specific proposals for dealing with stranded costs in the context of any restructuring proceedings that may be instituted by individual utilities.[765]

11. Accounting Treatment for Stranded Costs

No rehearing requests were filed on this issue. The Commission reaffirms Order No. 888's treatment of this issue.[766]

12. Definitions, Application, and Summary

In Order No. 888, we defined ''wholesale stranded cost'' in section 35.26(b)(1) as follows:

(1) *Wholesale stranded cost* means any legitimate, prudent and verifiable cost incurred by a public utility or a transmitting utility to provide service to:

(i) a wholesale requirements customer that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility; or

(ii) a retail customer, or a newly created wholesale power sales customer, that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility. [767]

We rejected requests by commenters in this proceeding to expand the definition to include the situation where a wholesale requirements customer or a retail-turned-wholesale customer ceases to purchase power from the utility without using the transmission services of that utility.[768] We explained that any costs that the utility might incur as a result of the loss of the requirements customer in this scenario would be outside the scope of this Rule. We noted that the premise of this Rule is that, where a customer uses Commission-mandated transmission access of its former power supplier to obtain power from a new generation supplier, the customer must pay the costs that were incurred to provide service to the customer under the prior regulatory regime. We indicated that if a customer leaves its utility supplier by exercising power supply options (such as access to another utility's transmission system or self-generation) that do not rely on access to the former seller's transmission, there is no nexus to the new open access rules.[769]

We also decided to retain the requirement that stranded costs be ''legitimate, prudent and verifiable,'' rejecting requests by some commenters to eliminate the term ''prudent'' from the definition of stranded costs.[770] We explained that a determination that a utility had a reasonable expectation of continuing to serve a customer would not, in all circumstances, mean that costs incurred by the utility were prudent. We said that prudence of costs, depending upon the facts in a specific case, may include different things: *e.g.,* prudence in operation and maintenance of a plant; prudence in continuing to own a plant when cheaper alternatives become available; prudence in entering into purchased power contracts, or continuing such contracts when buy-outs or buy-downs of the contracts would result in savings. We concluded that the Commission cannot make a blanket assumption that all claimed stranded costs will have been prudently incurred, but we clarified that we do not intend to relitigate the prudence of costs previously recovered.

Rehearing Requests—Definitions of ''Wholesale Stranded Cost'' and ''Wholesale Requirements Contract''

As discussed in Sections IV.J.1 and IV.J.6, *supra,* a number of entities ask the Commission to expand the scope of stranded cost recovery allowed under the Rule to include ''bypass'' situations (*i.e.,* situations in which a departing customer does not use its former supplier's transmission system to reach another supplier). Coalition for Economic Competition asks the Commission to revise the definition of ''wholesale stranded cost'' to accomplish that result. It notes, for example, that the reference in the definition to ''newly created wholesale power sales customer'' creates an ambiguity and may provide a loophole to evade stranded costs through municipal annexation.

El Paso expresses concern that a retail-turned-wholesale customer could attempt to avoid its stranded cost responsibility simply by having its outside power supplier be the ''wholesale transmission customer'' (*i.e.,* the entity that formally requests transmission service from the transmitting utility). El Paso asks the Commission to clarify that a retail-turned-wholesale customer is responsible to the transmitting utility for stranded costs regardless of whether it or its outside power supplier is the ''transmission customer'' of the transmitting utility. El Paso asks the Commission to revise section 35.26(c)(1)(vii) (which presently provides for recovery from retail-turned-wholesale customers through section 205–206 or 211–212 wholesale transmission rates) to provide for the recovery of stranded costs directly from retail-turned-wholesale customers (through an exit fee or lump sum payment).

Utilities For Improved Transition asks the Commission to expand the definition to include costs incurred to provide service to ''a wholesale requirements customer that loses retail load because of retail wheeling,

[763] As discussed in Section VI., we will treat SBA's request as a motion for reconsideration.

[764] 18 CFR 385.214 (1996).

[765] *See* FERC Stats. & Regs. at 31,845–46; *mimeo* at 614–15.

[766] *See* FERC Stats. & Regs. at 31,846–47; *mimeo* at 615–18.

[767] *Mimeo* at 768.

[768] FERC Stats. & Regs. at 31,849–50; *mimeo* at 624–26. The definition of ''retail stranded cost'' contains a similar requirement that the retail customer must become, in whole or in part, an unbundled retail transmission services customer of the public utility from which the customer previously received bundled retail services. We said that we would retain it for the same reasons discussed above.

[769] As we clarify in this Order, there is not a *sufficient* nexus to Commission-required transmission access in such circumstances. The Commission's decision not to allow utilities to seek recovery of stranded costs under the provisions of Order No. 888 if the customer leaves its historical power supplier by exercising power supply options that do not rely on access to the former supplier's transmission is based on the absence of a *direct causal* nexus between stranded costs and the availability and use of Commission-required transmission access. Self-generation and access to another utility's transmission system would have been options prior to the Rule.

[770] FERC Stats. & Regs. at 31,850; *mimeo* at 626–27.

municipalization of retail load, the creation of a new customer, or because retail customers have bypassed its system through transmission or distribution taps to other suppliers or by other means.'' [771] Utilities For Improved Transition argues that, in the case of retail wheeling and municipalization, these costs are incurred because of open access tariffs. It further submits that the Commission also should include costs incurred because of taps (interconnections) to other systems to avoid encouraging uneconomic bypass as a way to avoid stranded cost charges.

APPA expresses concern that the definition in section 35.26(b)(4) of ''wholesale requirements contract'' as ''a contract under which a public utility or transmitting utility provides any portion of a customer's bundled wholesale power requirements'' could be read as including a bundled sale of capacity regardless of whether the seller undertook to meet the customer's load growth. As a result, APPA submits that the definition could include coordination arrangements. It is APPA's position that the Commission could not, or should not, have intended to allow stranded cost recovery for such contracts. APPA asks the Commission to specify on rehearing that a ''wholesale requirements contract'' is a bundled power and transmission arrangement that includes the obligation to meet some or all of the customer's load growth, and that all other services are coordination arrangements to which the stranded cost recovery rules do not apply.

Commission Conclusion

We will reject the requests for rehearing that ask the Commission to expand the scope of stranded cost recovery allowed under the Rule to include situations in which a wholesale requirements customer (or a retail-turned-wholesale customer) ceases to purchase power from the utility without using the transmission services of that utility. As we explain in Sections IV.J.1 and IV.J.6, *supra,* any costs that the utility might incur as a result of the loss of the customer in these scenarios would be outside the scope of Order No. 888. However, as discussed in Section IV.J.6, we grant rehearing on the municipal annexation issue.

We share El Paso's concern that a retail-turned-wholesale customer should not be able to avoid its stranded cost responsibility simply by having its outside power supplier be the entity that formally requests unbundled transmission service from the utility. As we explain in Section IV.J.6, *supra,* in response to a similar concern expressed by Puget, we have revised the definition of ''wholesale stranded cost'' in section 35.26(b)(1)(ii) to cover this situation. As revised, that section provides that ''[*w]holesale stranded cost* means any legitimate, prudent and verifiable cost incurred by a public utility or a transmitting utility to provide service to: * * *. (ii) a retail customer that subsequently becomes, either directly or through another wholesale transmission purchaser, an unbundled wholesale transmission services customer of such public utility or transmitting utility.

We will deny Utilities For Improved Transition's request that the Commission expand the definition to include costs incurred to provide service to ''a wholesale requirements customer that loses retail load because of retail wheeling, municipalization of retail load, the creation of a new customer, or because retail customers have bypassed its system through transmission or distribution taps to other suppliers or by other means.'' Utilities For Improved Transition, in effect, is asking that the Commission allow the recovery of costs that may be stranded due to the loss of an indirect customer and to expand the scope of the ''wholesale stranded costs'' for which Order No. 888 provides an opportunity for recovery. As we discuss in Section IV.J.1, *supra,* the Commission does not believe it is appropriate to expand the scope of the stranded cost recovery opportunity provided under this Rule to include costs that may be stranded due to the loss of an indirect customer (*i.e.*, a customer of a wholesale requirements customer of the utility). The reasonable expectation analysis would apply only to the direct wholesale requirements customer of the utility, not to the indirect customer. A utility may seek to recover stranded costs from a direct wholesale customer (subject to the requirements of the Rule), but it is up to the direct wholesale customer, through its contracts with its customers or through the appropriate regulatory authority, to seek to recover stranded costs from its customers.

In response to APPA's argument that the definition of ''wholesale requirements contract'' in new section 35.26(b)(4) of the Commission's regulations could be read as including coordination arrangements, we clarify that it does not. The opportunity to recover stranded costs applies only to bundled power contracts where the utility can demonstrate that it incurred costs to provide service to a customer based on a reasonable expectation of continuing service to the customer beyond the contract term. Coordination arrangements could not meet the cost incurrence and reasonable expectation prerequisites of Order No. 888, and therefore a customer served under such an arrangement would not be subject to stranded cost charges.

Rehearing Requests—Relitigation of Prudence

A number of entities express concern that, notwithstanding the Commission's stated preference not to relitigate prudence, Order No. 888 leaves the door open for subsequent litigation of prudence issues. Centerior asks the Commission either to remove ''prudent'' from the definition or to clarify that ''prudent'' means all costs found prudently incurred by the state commissions. Centerior asks the Commission not to relitigate prudence in the operation and maintenance of a plant or the prudence of continuing to own a plant when cheaper alternatives become available. Other entities (including EEI, PSE&G, and Nuclear Energy Institute) similarly ask the Commission to clarify that it does not intend to relitigate costs that are already in rates when calculating the revenue stream estimate. Nuclear Energy Institute states that, in the case of nuclear plants, significant prudence proceedings have already been conducted and, by definition, the embedded capital costs included in current rates to customers are prudent.

PSE&G recommends that if costs that form the basis for a utility's claimed stranded costs are already included in filed rates and are no longer subject to refund, those costs should be treated as *per se* prudent. Southern states that if the Commission does not strike the word ''prudent'' from the definition of stranded costs, at a minimum it should modify the Rule to establish a rebuttable presumption of prudence that must be overcome by the departing customer.

PSE&G and Carolina P&L submit that if prudence challenges under the Rule are retained on rehearing, they should be subject to the same standards as any other prudence challenge, namely the ''reasonable person test'' under which prudent costs are those ''which a reasonable utility management * * * would have made, in good faith, under the same circumstances, and at the relevant point in time.'' [772] PSE&G and Carolina P&L ask the Commission to limit the prudence review to the reasonableness of the costs that were incurred to provide wholesale requirements service based on the

[771] Utilities For Improved Transition at 17.

[772] Both note that this is the prudence standard that the Commission applied in Order No. 636.

utility's reasonable expectation of continued service. They ask the Commission to clarify that it will not permit prudence proceedings to devolve into collateral attacks on stranded cost recovery and unfocused debates on the sufficiency of the utility's efforts to adapt to changes in the industry, such as its decisions on staffing reductions and asset write-offs.

Commission Conclusion

In Order No. 888, we specifically stated that we do not intend to relitigate the prudence of costs previously recovered but that we would not preclude parties from raising prudence in stranded cost proceedings. Because we believe that this approach adequately ensures that the prudence of costs previously recovered at this Commission or a state commission will not be relitigated for stranded cost purposes, we will reject the rehearing requests that seek elimination of the term ''prudent'' from the definition of stranded costs.[773] However, we make certain clarifications below in response to the rehearing petitions.

As an initial matter, we clarify that the Commission's determination in Order No. 888, which is reaffirmed here, is the same approach the Commission traditionally has followed regarding prudence matters.[774] Costs are assumed prudent unless a party or the Commission raises a serious doubt as to prudence; then the burden is on the utility to prove that costs were prudently incurred.[775] If costs have previously been recovered in rates (either following an explicit prudence determination or based on an implicit assumption of prudence because no one raised prudence), they *cannot* be relitigated. However, if prudence has not previously been litigated or if certain costs or activities have become imprudent,[776] a party may raise the issue as it pertains to *future* cost recovery.[777] The Commission intends to apply the same prudence standards with regard to future cost recovery, including stranded costs.

We further clarify that we do not intend to relitigate, for purposes of stranded cost determinations involving retail-turned-wholesale customers or unbundled retail customers, the prudence of costs for which rate recovery has been allowed by state commissions. Similarly, in calculating the revenue stream estimate, we do not intend to relitigate the prudence of any costs for which rate recovery has been allowed by this Commission or a state commission.[778]

In response to PSE&G and Carolina P&L, we also clarify that, in cases in which we do entertain stranded cost claims, the standard to be used for reviewing the prudence of a utility's costs is the ''reasonable person'' test that we apply in other contexts.[779] This test gives utility managers ''broad discretion in conducting their business affairs and in incurring costs necessary to provide services to their customers.'' [780] It asks whether the costs are those ''which a reasonable utility management * * * would have made, in good faith, under the same circumstances, and at the relevant point in time.'' [781] We clarify that we do not intend to permit prudence proceedings to become an opportunity for collateral attacks on stranded cost recovery.

K. Other

1. Information Reporting Requirements for Public Utilities

In the Final Rule, the Commission indicated that it will not now eliminate the public disclosure of allegedly competitively sensitive, proprietary, or otherwise confidential data submitted to the Commission on Form No. 1, as well as on other Commission forms. [782] It explained that the information it collects from public utilities is necessary to carry out its jurisdictional responsibilities and is used, among other things, to evaluate the reasonableness of cost-based rates subject to the Commission's jurisdiction and the operation of power markets.[783] Moreover, the Commission noted its explanation in ConEd:

> [r]eports required to be submitted by Commission rule and necessary for the Commission's jurisdictional activities are considered public information. 18 C.F.R. § 388.106. In addition, the Commission has long required jurisdictional utilities to submit Form 1 data on a form that states on its cover that the Commission does not consider the material to be confidential. [[784]]

The Commission expressed sensitivity to the lack of symmetry in the generation information we require from traditional public utilities, particularly those that have market-based rate authority, and the generation information required from other public utilities (*e.g.*, public utility marketers) authorized to sell at market-based rates, but explained that the record in the proceeding is insufficiently developed to make and support a well-informed decision requiring a different reporting scheme, particularly given the industry's current rapid pace of change. Also, the Commission indicated that it was not persuaded that the burdens borne by traditional public utilities (primarily annual reports submitted months after-the-fact) are impairing the competitiveness of these utilities so much that we must act hastily now, instead of deferring a decision to a more appropriate proceeding.

However, the Commission stated that it will monitor its reporting requirements to make sure that they are needed, fair to all segments of the industry, and consistent with the workings of a competitive environment.

Rehearing Requests

Allegheny asserts that this proceeding is the proper forum to evaluate the public disclosure of information required from public utilities because it is necessary to avoid disparate treatment of market participants that violates the comparability standard and leads to market distortions. It argues that the Commission should eliminate the requirement to file data on Form No. 1 and other informational filings, or alternatively the Commission should protect the information as proprietary and confidential.

Centerior argues that the Commission should eliminate the public disclosure of the cost-based generation rates and provide for symmetry between the information provided by public utilities

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[773] For the same reason, we will reject Southern's request that we establish a rebuttable presumption of prudence that must be overcome by the departing customer.

[774] *See* Minnesota Power & Light Company, Opinion No. 86, 11 FERC ¶ 61,312 at 61,644–45 (1980).

[775] *Id.* at 61,644; Anaheim Riverside, et al. v. FERC, 669 F.2d 799, 809 (D.C. Cir. 1981).

[776] A utility has an ongoing prudence obligation. As pointed out in Order No. 888, although an investment or a contract may have been prudently incurred, it may become imprudent at a later point in time not to dispose of assets or not to buy-out contracts that have become uneconomic, assuming this results in net benefits to customers.

[777] *See* Canal Electric Company, 47 FERC ¶ 61,044 at 61,127, *reh'g denied*, 49 FERC ¶ 61,069 (1989) (if a party raises prudence issues in a later proceeding, any future finding concerning prudence will have no effect on past rates).

[778] Although we will not go so far as to characterize these costs as ''*per se* prudent'' (as requested by PSE&G), in effect, the result is the same because we will not allow the prudence of such costs to be relitigated.

[779] *See* New England Power Company, 31 FERC ¶ 61,047 at 61,081–84 (1985), *aff'd sub nom.*, Violet v. FERC, 800 F.2d 280, 282–83 (1st Cir. 1986). We note that this is the same standard that the Commission has used for reviewing the prudence of a pipeline's Order No. 636 gas supply realignment costs. *See* Texas Eastern Transmission Corporation, 65 FERC ¶ 61,363 (1993).

[780] New England Power Company, 31 FERC at 61,084.

[781] *Id.*

[782] FERC Stats. & Regs. at 31,851–52; *mimeo* at 631–32.

[783] *See, e.g.*, Consolidated Edison Company of New York, Inc. and Central Hudson Gas & Electric Corp., 72 FERC ¶ 61,184 at 61,891 (1995) (*ConEd*).

[784] 72 FERC at 61,891.

and power marketers by eliminating the reporting requirements.

EEI indicates that it intends to petition the Commission for further action on information reporting requirements in the near future. It adds that it seeks to work with the Commission in streamlining the reporting process and in creating a level playing field.

Commission Conclusion

We are not persuaded that the information reporting requirements for public utilities need to be changed *at this time.* Very simply, it is premature to take such a step at a time when much of the industry is still under cost-based rate regulation for sales of electric energy and when corporate restructuring, including utility mergers, is occurring at a rapid pace. On rehearing, entities have merely reiterated the arguments that we previously addressed in the Final Rule and have presented no evidence that the competitiveness of traditional public utilities is being impaired by their having to submit primarily annual reports that are filed months after the fact. Accordingly, we will continue to require public utilities to submit the information required by our rules and regulations and we will monitor our reporting requirements as the industry environment continues to change.

2. Small Utilities

The Commission noted that it was sympathetic to the array of concerns raised by small public utilities and small transmission customers and explained that the regulations it was adopting include waiver provisions under which public utilities and transmission customers, and non-public utility entities seeking exemption from the reciprocity condition, may file requests for waivers from all or part of the Commission's regulations or for special treatment.[785] However, the Commission explained, it is difficult to imagine any circumstance that would justify waiving the requirements of this Rule for any public utility that is also a control area operator.

The Commission recognized that it might be a financial burden on small public utilities to unbundle generation from transmission, follow standards of conduct that separate transmission personnel from wholesale marketing personnel, and maintain an OASIS. In addition, the Commission explained that for small public utilities that own no generation and buy at wholesale on a radial transmission line from another utility's grid or if their service territory is part of another utility's control area, the small public utility should be permitted to make a showing that it should be exempt from all or some of the Rule.

The Commission further explained that because the possible scenarios under which small entities may seek waivers from the Final Rule are diverse, they are not susceptible to resolution on a generic basis and the Commission will require applications and fact-specific determinations in each instance.

In addition, the Commission indicated that it will apply the same standards to any entity seeking a waiver. The Commission explained that this includes public utilities seeking waiver of some or all of the requirements of the Rule, as well as non-public utilities seeking waiver of the reciprocity provisions contained in the pro forma open access tariff. The Commission concluded that it would not apply the open access reciprocity provision to small non-public utilities that are not control area operators and either do not own or control transmission or have transmission that no one is likely to ask to use. However, the Commission explained that they will have to apply for this waiver and demonstrate that they qualify for the waiver.

Rehearing Requests

APPA asserts that absent a finding that a non-public utility has market power or has exhibited undue discrimination, the non-public utility should be granted a waiver.

Michigan Systems asks that the Commission modify the Rule to provide a blanket waiver for systems that by their nature cannot have market power over transmission and do not have the personnel to separate functions. It also asserts that the Final Rule waiver procedure is cumbersome and time consuming.

Tallahassee asks the Commission to clarify that it will liberally apply its waiver policy to small public utilities even if they run a control area. It asserts that the proper focus of concerns over competition are a utility's size, its ability to manipulate the market, and how it operates its control room.

CAMU asks the Commission to clarify that the small utilities waiver will be generally available to those entities lacking market power because only utilities with market power are capable of subverting the transmission market.

Commission Conclusion

The issues raised with respect to waivers for small utilities are more appropriately addressed in individual fact-specific proceedings. As we explained in the Final Rule,

> [b]ecause the possible scenarios under which small entities may seek waivers from the Final Rule are diverse, they are not susceptible to resolution on a generic basis and we will require applications and fact-specific determinations in each instance. We note here that any waivers that we may grant depend upon the facts presented in each case.[786]

Indeed, we have granted a variety of waiver requests by small utilities since issuance of the Final Rule.[787]

3. Regional Transmission Groups

a. Incentives for RTGs To Form and Resolve Regional Transmission Issues

In the Final Rule, the Commission expressed its continued support for the development of RTGs and encouraged regional tariffs.[788] To further encourage the development of RTGs, the Commission stated that it will accept regional open access transmission tariffs developed by RTGs that are consistent with the objectives of this Rule.

b. Deference To RTGs to Develop Regional Tariffs and Prices

In the Final Rule, the Commission indicated its intent to give deference to the planning, dispute resolution, and decisionmaking processes of an RTG. [789] With respect to pricing proposals submitted by RTGs, the Commission stated that RTGs may be able to develop solutions to such problems as loop flows through innovative flow-based pricing methodologies.

Rehearing Requests

No requests for rehearing addressed this matter.

4. Pacific Northwest

In the Final Rule, the Commission encouraged the filing of regional open access transmission tariffs.[790] It also explained that the Final Rule pro forma tariff contains provisions allowing utilities to modify tariff terms to reflect prevailing regional practices. The Commission concluded that this should permit entities in the Pacific Northwest

[785] FERC Stats. & Regs. at 31,853–54; *mimeo* at 636–38. The Commission also noted that non-public utility entities could request that the Commission find that they can satisfy the reciprocity condition without meeting all or some of the requirements that public utilities must meet.

[786] FERC Stats. & Regs. at 31,854; *mimeo* at 637–38.

[787] Black Creek Hydro, Inc. (*Black Creek*), 77 FERC ¶ 61,232 (1996); Midwest Energy, Inc., 77 FERC ¶ 61,208 (1996).

[788] FERC Stats. & Regs. at 31,854–55; *mimeo* at 640.

[789] FERC Stats. & Regs. at 31,855; *mimeo* at 642.

[790] FERC Stats. & Regs. at 31,856; *mimeo* at 644–45.

to address unique circumstances that exist in the Pacific Northwest and to incorporate prevailing regional practices (*e.g.*, treatment of hydropower generation in the priority of dispatch) into their open access transmission tariffs.

Rehearing Requests

No requests for rehearing addressed this matter.

5. Power Marketing Agencies

a. Bonneville Power Administration (BPA)

In the Final Rule, the Commission stated that BPA is not a public utility under section 201(e) of the FPA and, thus, is not subject to the requirements of this Rule to put the Final Rule pro forma tariff into effect.[791] However, the Commission indicated three circumstances under which the Commission may review BPA's transmission access and pricing policies.

With respect to stranded costs, the Commission clarified that the Rule addresses only stranded costs recovered by public utilities under the FPA and transmitting utilities (including BPA) that are subject to mandatory transmission requests under FPA section 211. It explained that the Rule does not address stranded cost recovery by BPA under the Northwest Power Act.

Rehearing Requests

BPA asks the Commission to clarify that it did not intend to address stranded cost recovery by BPA under either the Northwest Power Act or section 212(i) of the FPA. If Order No. 888 is intended to govern stranded cost recovery by BPA in the case of Commission-ordered transmission under section 211, BPA asks the Commission for an opportunity to brief the issue on rehearing.

Commission Conclusion

We clarify that our review of stranded cost recovery by BPA would take into account the statutory requirements of the Northwest Power Act and the other authorities under which we regulate BPA (*e.g.*, DOE delegation for interim rate approval) and/or section 212(i), as appropriate.

b. Other Power Marketing Agencies

In the Final Rule, the Commission explained that Federal power marketing agencies (PMAs) are not public utilities as defined under section 201(e) of the FPA and, thus, are not required by this Rule to file non-discriminatory open access transmission tariffs.[792] However, the Commission did state that to the extent a PMA receives open access transmission service from a public utility, it is subject to the reciprocity provisions in the utility's pro forma tariff.[793]

With respect to SEPA's concern that the proposed point-to-point tariff has a one MW minimum scheduling requirement, but many of its customers have loads of less than one MW, the Commission clarified that the Final Rule pro forma tariff will allow SEPA to continue to schedule service for these customers. The Commission also clarified that SEPA, as a seller of power to multiple purchasers inside several control areas, is eligible to receive network service.

Rehearing Requests

Entergy asks the Commission to clarify that SEPA can obtain network service only in the same manner as any other customer and that there was no intent in the Rule to create a special type of network service for SEPA.

Commission Conclusion

We will clarify that for purposes of obtaining network service SEPA is to be treated as any other customer.

6. Tennessee Valley Authority

In the Final Rule, the Commission stated that TVA is not a public utility under section 201(e) of the FPA and, thus, is not required to file a non-discriminatory open access transmission tariff under this Rule.[794] However, the Commission explained, if TVA receives open access transmission service from a public utility, it is subject to the reciprocity provision in the utility's pro forma tariff.[795]

Rehearing Requests

No requests for rehearing addressed this matter.

7. Hydroelectric Power

Non-Firm Transactions

In the Final Rule, the Commission explained that it will permit entities to incorporate prevailing regional practices (*e.g.*, treatment of hydropower generation in the priority of dispatch) into regional open access transmission tariffs.[796] This, the Commission indicated, should permit entities in a region to resolve concerns over the scheduling of non-firm hydropower.

Commission's Licensing Practices

The Commission explained that the issues raised by National Hydropower with respect to the Commission's hydroelectric licensing practices are beyond the scope of this rulemaking. The Commission also noted that these issues were raised in a petition to the Commission to revise hydroelectric licensing procedures, filed on July 10, 1995. That is the proper proceeding, the Commission explained, in which to address the Commission's hydroelectric licensing practices.

Rehearing Requests

No requests for rehearing addressed this matter.

8. Residential Customers

In the Final Rule, the Commission stated that it was convinced that the proposed changes for wholesale markets will benefit residential consumers. [797] Moreover, the Commission explained that the Rule does not require retail transmission access for retail customers of any size and does not require any changes in programs such as assistance to low-income and elderly consumers and weatherization and energy conservation, which are, and will remain, under the jurisdiction of the individual states. The Commission further noted that the Rule contains several safeguards to maintain the ability of states to impose conditions on retail access, such as conditions that help to protect residential customers from becoming the residual payer of stranded costs.

Rehearing Requests

No requests for rehearing addressed this matter.

9. Miscellaneous Issues

Unconstitutional Taking of Property

Union Electric declares that the imposition of an onerous regime of mandates governing what utilities must and must not do with their own property constitutes an unconstitutional taking of their property in violation of the takings clause.

[791] FERC Stats. & Regs. at 31,857–58; *mimeo* at 648–49.

[792] The Commission noted, however, that PMAs are transmitting utilities subject to requests for mandatory transmission services under section 211 of the FPA.

[793] FERC Stats. & Regs. at 31,858; *mimeo* at 650–51.

[794] The Commission noted, however, that TVA is a transmitting utility subject to requests for mandatory transmission services under section 211 of the FPA.

[795] FERC Stats. & Regs. at 31,858–59; *mimeo* at 651–52.

[796] FERC Stats. & Regs. at 31,859; *mimeo* at 654–55.

[797] FERC Stats. & Regs. at 31,860; *mimeo* at 656.

Commission Conclusion

Union Electric has provided no valid legal or factual basis to support its arguments that our final orders result in an unconstitutional taking of property in violation of the takings clause. We have a statutory obligation under the FPA to remedy undue discrimination in the transmission or sale of electric energy subject to our jurisdiction. In Order No. 888, we concluded that unduly discriminatory and anticompetitive practices exist today in the electric industry and that such practices will increase as competitive pressures continue to grow in the industry.[798] Accordingly, we exercised our remedial authority by issuing Order Nos. 888 and 889 to ensure that unduly discriminatory practices can no longer occur.[799]

In exercising our remedial authority, we did not alter the traditional principle that a utility is entitled to a reasonable opportunity to recover its prudently incurred costs.[800] Union Electric has provided no evidence that it will not be adequately compensated for whatever services it may provide on its system following the effectiveness of Order Nos. 888 and 889. To the extent a third party uses Union Electric's transmission system, it must still compensate Union Electric for that usage, as has happened in the past. There simply cannot be an unconstitutional taking of property when public utilities continue to have the right to file for and receive rates that provide them a reasonable opportunity to recover their prudently incurred costs. Indeed, as the Supreme Court has explained, ''[a]ll that is protected against, in a constitutional sense, is that the rates fixed by the Commission be higher than a confiscatory level.'' [801] Union Electric has made no showing that Order Nos. 888 and 889 will result in its rates being set at a confiscatory level. Furthermore, the rate that Union Electric may charge for transmission service is currently before the Commission in Docket No. OA96–50–000 and Union Electric should make arguments regarding the reasonableness of its transmission rate in that proceeding. [802] Moreover, Union Electric is free to propose changes to the rate it charges for transmission from time to time to ensure that it is being fairly compensated for its investment in its transmission system, as well as any expenses it incurs in providing such service.

Section 206 Complaints

Cleveland states that, unfortunately, it has suffered significantly because of denied transmission access and the inefficacy of long-delayed enforcement relief under section 206 of the FPA. Thus, Cleveland states that the Commission must announce its intention to enforce transmission and related obligations and, having made that pronouncement, take whatever steps are necessary to do so.

TAPS states that throughout the Final Rule the Commission points to complaint procedures to redress complaints against transmission providers' open access tariffs and argues that the Commission must clarify that these complaints will receive expedited treatment.

Commission Conclusion

The Commission has a statutory obligation to act if it finds, upon its own motion or upon complaint, that any rate, charges, or classification demanded, observed, charged, or collected by any public utility, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, and to determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed. Moreover, section 206(b) of the FPA requires that whenever the Commission institutes a proceeding under this section it must establish a refund effective date. In carrying out its obligations under section 206 of the FPA, the Commission acts as expeditiously as is possible, given the complexities of the issues at hand, its other workload and its level of staffing. The Commission will continue to work as expeditiously as possible in resolving section 206 proceedings, as well as in resolving all of the other matters that come before it. Given the critical importance of timely, comparable transmission access in fostering competitive wholesale power markets, the Commission intends to vigorously enforce utilities' open access obligations. [803]

We would emphasize that filing complaints with the Commission is not the only avenue that transmission customers (or potential customers) can pursue to raise their concerns. Under the Open Access Transmission Tariff, parties can and should avail themselves of the Dispute Resolution Procedures set forth in section 12 of the pro forma tariff. This section provides that an arbitrator must render a decision and notify the parties within ninety days of appointment.

NRC Remedial Orders

Cleveland asks that the Commission clarify that directives requiring non-discriminatory treatment of transmission customers are not intended to override, but are expected to accommodate, valid remedial orders of the NRC imposed in the form of nuclear license conditions.

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[798] FERC Stats. & Regs. at 31,682–84; *mimeo* at 136–142.

[799] Union Electric argues that

[t]he dramatic changes in the regulatory scheme set forth in the final rules impose extensive constraints on Union Electric's use of its own property, forcing Union Electric to throw open its transmission system to use by third parties, dictating the terms and conditions of that usage and, in the process, providing for the physical occupation of Union Electric's transmission system by third parties' facilities and power. (Union Electric at 59).

However, as Union Electric's own words demonstrate, these so-called dramatic changes are no more than a summary of the Commission's current authority and the Commission's current regulation of public utilities. Under the FPA, Union Electric can only provide non-unduly-discriminatory jurisdictional services to third parties and must obtain Commission approval of the rates, terms and conditions pursuant to which it provides such service. Moreover, under Order No. 888, third parties may ''physically occupy'' Union Electric's transmission system only pursuant to the terms of Union Electric's tariff and contracts entered into with Union Electric, just as third parties previously had the right to ''physically occupy'' its transmission system.

Finally, we are confused about Union Electric's argument in that in the pending merger proceeding involving its proposed merger with Central Illinois, it argues that the open access tariff of the merged company will be used to mitigate market power. *See* El Paso Electric Company and Central and South West Services Inc., 68 FERC ¶ 61,181 at 61,914 (1994), *dismissed,* 72 FERC ¶ 61,292 (1995). Union Electric cannot argue that the tariff mitigates market power at the same time it argues that the requirement to have the tariff is prohibited as an unconstitutional taking of property.

[800] *See, e.g.,* FPC v. Hope Natural Gas Company, 320 U.S. 591 (1944). Moreover, to the extent Union Electric's facilities are used for public service, Union Electric is entitled to recover all prudently invested capital in the public utility enterprise. We have not changed that principle.

[801] FPC v. Texaco, 417 U.S. 380, 391–92 (1974); *see also* FPC v. Natural Gas Pipeline Co., 315 U.S. 575, 585 (1942).

[802] All public utilities subject to Commission jurisdiction were required to file open access compliance tariffs, including the rate to be charged for various types of transmission service, by July 9, 1996.

[803] With specific regard to Cleveland and CEI, we note that the Commission has expended considerable resources over the years dealing with and resolving a significant number of section 205 and 206 proceedings in which these companies contested a plethora of issues. As the D.C. Circuit noted, these two entities have a particularly hostile relationship. City of Cleveland v. FERC, 773 F.2d 1368, 1371 (1985). This has led to a situation where these contentious entities are more likely to contest issues before the Commission than to resolve them. Since 1993 alone, the Commission has addressed and resolved at least 9 proceedings involving disputes between Cleveland and CEI. Indeed, at this time, the Commission has only several ongoing proceedings involving disputes between these entities. In addition, the parties are in disagreement over transmission issues in the pending merger application involving CEI and Ohio Edison.

Commission Conclusion

We will deny Cleveland's requested clarification because it is overly broad. However, we do clarify that we view our jurisdiction under the FPA and the NRC's jurisdiction as complementary. In that regard, a utility subject to the Commission's jurisdiction and to the NRC's jurisdiction would have to comply with the orders of both commissions. Moreover, just as the NRC cannot and does not enforce this Commission's orders, it is not within our jurisdiction to enforce orders of the NRC. In the event that an entity believes that it must, but cannot, comply with separate orders issued by this Commission and the NRC, it should present evidence to this Commission and/or the NRC of such a conflict. To the extent necessary and appropriate, we would attempt to resolve any such conflicts subject to our jurisdiction under the FPA.

Retail Customers' Future Access to Transmission Capacity

IL Industrials states that the Commission should fashion safeguards to prevent monopolization of transmission capacity by wholesale customers before retail customers are entitled to engage in direct access. Alternatively, IL Industrials states that the Commission should specify that this issue will be addressed in the CRT NOPR proceeding and that contracts or other arrangements affecting available transmission capacity will be subject to safeguards to protect retail customer transmission access.

Commission Conclusion

This matter is beyond the scope of this proceeding. We have no way of ascertaining the transmission capacity that a retail customer may require in the future should it become entitled to engage in direct access through a state-approved program or voluntary action by its current transmission provider. We cannot require a transmission provider to keep transmission capacity available for all possible transactions that a retail customer may possibly enter into in the future. Just as transmission customers must take the system as it exists at the time of a request, so must future potential transmission customers take the system as it exists at the time of their request.

Transaction Accommodation Arrangements

NCMPA argues that the Commission failed to address the problem of market power arising from a transmission provider's control over transaction accommodation arrangements, which it states are arrangements needed by transmission dependent utilities to accommodate third-party transactions within an existing power supply relationship between the TDU and the transmission provider. NCMPA explains that this problem is most apparent where there is a comprehensive power supply relationship that purports to establish most or all of the TDU's bulk power needs. For example, NCMPA points out that because of Duke Power Company's control over transaction accommodation arrangements, NCMPA has been frustrated in its attempts to pursue beneficial bulk power transactions with parties other than Duke. NCMPA asks that the Commission require transmission providers to provide these arrangements on a comparable basis, state that it will take prompt action to remedy a denial of comparable arrangements, and require that any utility seeking specific permission for any action premised on the mitigation of market power to demonstrate that it has offered comparable transaction accommodation arrangements to any TDU that requires such arrangements.

Commission Conclusion

NCMPA's concerns appear to be related to its existing power supply arrangements, not with new service under the pro forma tariff. These concerns are more appropriately addressed in a case-specific section 206 complaint proceeding before the Commission.

Ohio Valley—Power to Uranium Enrichment Facility

Ohio Valley asks the Commission to clarify that the orders do not apply to Ohio Valley so that Ohio Valley can continue to provide the lowest possible cost, and most reliable, service to the Piketon, Ohio uranium enrichment facility owned by the United States.[804] Otherwise, Ohio Valley argues, compliance could result in increased costs to the United States and to the customers of the utilities participating in providing power to the enrichment facility. Ohio Valley seeks to avoid unnecessary interference with its ability to carry out its obligations under the existing agreements, but is amenable to reasonable and prudent use of its transmission system in accordance with sections 211 and 212.[805]

Commission Conclusion

Ohio Valley's rehearing request is essentially an application for waiver that is not properly addressed in this proceeding. By order issued July 2, 1996, we explained that because of the fact-specific nature of waiver requests the Commission will not address such requests in a generic rulemaking proceeding, but will require entities seeking waiver to submit separate, fact-specific requests that will be docketed in separate OA proceedings.[806] Subsequently, Ohio Valley filed a separate petition for waiver in Docket No. OA96–126–000 that effectively reiterated the arguments made in its rehearing request. The Commission will address Ohio Valley's fact-specific arguments in Docket No. OA96–126–000.

Exchanges

Several entities argue that exchanges should be permitted without a requirement that customers book capacity for each direction the power will flow and parties should not each have to pay the full reservation charge.[807] Because point-to-point customers can change receipt points without payment of additional charges, they argue that the same logic applies to exchanges.

Commission Conclusion

An exchange between two utilities has traditionally been viewed as two separate transactions (two one-way services) from the transmitting utility's planning and reservation perspective and has been priced as two separate services. Consistent with this approach, the pro forma tariff only allows changes to points of receipt and delivery for point-to-point service on a *non-firm* basis at no extra charge. Any changes to points of receipt and delivery on a *firm* basis must be submitted to the Commission as new applications. However, we note that comparability is achieved if the transmission provider charges itself and its transmission customers for point-to-point service on a consistent basis, whether that be separately for both directions or on a bidirectional basis.

Various Rate Matters

VT DPS and Valero argue that rates ''should be based on a definition and quantification of a core of transmission function lines and substations for use in wholesale wheeling rather than on the basis of a rolled-in rate for the entire

[804] Ohio Valley states that the facility is now leased by the United States to the United States Enrichment Corporation.

[805] Dayton filed a motion to reject Ohio Valley's request for rehearing, arguing that it was really an application for waiver. (Dayton Motion to Reject).

[806] Order Clarifying Order Nos. 888 and 889 Compliance Matters, 76 FERC ¶ 61,009 (1996).

[807] *E.g.*, VT DPS, Valero, APPA.

transmission network.'' VT DPS states that ''[i]n order to insure against cross subsidization, the tariffs should provide for the imposition of a Local Transmission System Access Charge to recover the costs of the facilities used to provide service to customers in this category.'' (VT DPS at 23–24; Valero at 8–10).

American Forest & Paper argues that

> the Commission's proposal includes as part of the transmission revenue requirement amounts attributable to the utility's use of its own transmission system to effectuate off-system sales and revenues received from transmission customers taking service under existing contracts and tariffs but not under the new transmission tariffs. By failing to subtract such revenues from the revenue requirement used to determine rates for services rendered under the new tariffs, the utility effectively recovers these amounts twice: once from its off-system sales and transmission customers not taking service under the new tariffs and a second time from its customers taking service under the proposed new tariffs.''[808]

American Forest & Paper asserts that to eliminate this double-recovery, the Commission should adopt PacifiCorp's proposal in Docket No. ER95–1240. American Forest & Paper further declares that the Commission must demonstrate that the charges imposed on customers of network wheeling service are commensurate with the benefits that they receive.

Commission Conclusion

We are not prepared to mandate in a generic proceeding such as this that all transmission rates must be established by function or that a specific pricing methodology should be used. Our rate policy, as set forth in the Transmission Pricing Policy Statement, is to encourage flexible and innovative rate approaches by the electric industry. Mandating a single methodology for the entire industry would certainly defeat that goal. While the Commission welcomes new and innovative proposals, we will not impose a generic change in this proceeding. As always, utilities are free to propose the use of a functional pricing method in their compliance filings or in any section 205 filing it may submit to the Commission.

Federal Government Contract Clauses

ConEd asserts that the Commission must modify the pro forma tariff to include certain Federal government required anti-discrimination clauses. According to ConEd, these clauses require that all of Con Edison's transmission providers agree to be bound by certain provisions of the federal subcontractor regulations. ConEd suggests that the ''Commission state that Con Edison and similarly-situated utilities be permitted to comply with the federal subcontracting requirements by inserting such clauses in their service agreements for transmission services.'' (ConEd at 17–18).

Commission Conclusion

The Commission disagrees with ConEd's assertion that the Commission must modify the pro forma tariff to include certain Federal government anti-discrimination clauses. The Commission does not dispute that certain parties must comply with provisions of the federal subcontractor regulations for particular transactions that may involve the provision of transmission service. However, we do not agree that these provisions must be incorporated into the pro forma tariff. The contracting obligation raised by ConEd is independent of the pro forma tariff and more appropriately addressed in a separate contract between the parties to the purchase or the service agreements for transmission services. The Commission notes that this is apparently how the issue has been handled in the past by ConEd because its tariffs previously filed with the Commission (pre-NOPR) did not include such anti-discrimination clauses.

V. Environmental Statement

Summary

The Commission prepared an environmental impact statement (EIS) to evaluate the environmental consequences that could result from adopting the Rule. We did so largely in response to the claims of several commenters who charge that the Rule will have significant adverse environmental effects. As described in Order No. 888:

> Although a number of issues were raised, by far the most prominent concern arises from the theory that competitive market conditions created by the rule will provide an advantage to power suppliers who produce power from coal-fired facilities that are not subject to stringent controls on nitrogen oxides (NO_X) emissions. Under this theory, these facilities, located primarily in the Midwest and South, will, as a result of the rule, generate more power and emit more NO_X, which will contribute to ozone formation. The ozone could add to pollution both in those regions and more significantly in the Northeast, to which area such pollutants could be transported. Those who propound this theory argue that it is the responsibility of the Commission, using its authority under the Federal Power Act, to effect environmental controls that will mitigate what they predict will be significant increases in NO_X emissions associated with this rule.[809]

The EIS recognizes that the electric industry will contribute to air emissions regardless of whether the Rule is adopted. The purpose of the EIS is to analyze to what extent the Rule is likely to affect those emissions.

Many variables can influence the impacts of the Rule and the EIS uses a modeling framework that incorporates a range of assumptions about these variables. The most significant variable is likely to be the future prices of the two primary fuels used to generate electricity—coal and natural gas. Government and industry price forecasts were used to construct two alternative fuel price assumptions: (1) that the price of natural gas will increase relative to the price of coal; and (2) that the relative price of coal and natural gas will remain constant. These assumptions form the basis for two base cases that project the environmental impacts of developments in the electric industry without the Rule. The EIS then makes assumptions about the effects of the Rule to create three scenarios that project a range of possible results. It compares the environmental impacts projected in the scenarios with those projected in the base cases to determine the effect of the Rule.[810] The analysis set forth in the EIS demonstrates that the Rule will not in any significant respect affect overall trends in NO_X emissions.

Subsequent to the issuance of Order No. 888, the Environmental Protection Agency (EPA) conducted a review of the Commission's FEIS in which EPA employed alternative assumptions for a number of model inputs. In doing so, EPA stressed that ''[n]aturally there can be differences among reasonable analysts concerning the assumptions used in such an analysis'' and that ''EPA believes the assumptions used by the FERC and those used by EPA both lie within the reasonable range.''[811] EPA has concluded that the Rule is unlikely to have any significant adverse environmental impact in the immediate

[808] American Forest & Paper at 24.

[809] FERC Stats. & Regs. at 31,860; *mimeo* at 657–58 (footnote omitted).

[810] The EIS also conducts sensitivity analyses of how projected air emissions might change if key assumptions in the analysis are changed. These analyses include two frozen efficiency reference cases which represent a world in which: (1) the Commission reverses current pro-competitive transmission policy (inconsistent with congressional mandates under EPAct); (2) states cease to adopt programs to improve industry efficiency; and (3) electric companies cease to improve operations or to enter into mutually beneficial transactions.

[811] Letter of May 22, 1996 from Mary Nichols, Assistant Administrator for Air and Radiation, EPA, to Kathleen McGinty, Chair, CEQ.

future, and that implementation of the Rule should go forward without delay. In reaching these conclusions, EPA concurred that the Commission conducted an adequate NEPA analysis of the environmental impacts of the Rule under a range of possible scenarios. EPA also agreed that the Commission made a reasonable choice of models with which to conduct the analysis and, as noted above, made assumptions for various factors input into the model that lie within the range of reasonable assumptions.

EPA also concurred with the Commission that NO_X emissions increases associated with the Rule, if any, should be addressed as part of a comprehensive NO_X emissions control program developed by EPA and the states pursuant to the Clean Air Act. EPA committed to use its Clean Air Act authority to support successful completion of this program, and stated that it will establish a NO_X cap-and-trade program through Federal Implementation Plans if some states are unwilling or unable to act in a timely manner.

In a letter dated May 13, 1996, the EPA Administrator referred Order No. 888 to CEQ.[812] In doing so, EPA suggests that if the Ozone Transport Assessment Group (OTAG) and Clean Air Act processes fail to produce the necessary pollution limitations in a timely manner, EPA will call upon all other interested federal agencies to assist in solving the problem. EPA would ask the Commission to contribute by examining, through a Notice of Inquiry, possible strategies for mitigating NO_X emissions increases associated with the Rule.

The Commission subsequently responded by issuing an order stating that if EPA concludes that the OTAG process has not succeeded in meeting its objectives in a timely manner, the Commission would initiate a Notice of Inquiry to further examine what mitigation might be permissible and appropriate under the Federal Power Act. Such an inquiry would solicit public comment on how to assess appropriately the air pollution impacts attributable to the Rule, suitable ways in which to address such impacts, if any, and the scope of the Commission's authority to address such impacts. The Commission also stated that, under the extraordinary circumstances in which EPA would undertake a Federal Implementation Plan, the Commission would agree to initiate contemporaneously a rulemaking to propose possible mitigation that could be undertaken by the Commission under the FPA. Such a rulemaking would be undertaken on the basis of the Notice of Inquiry discussed above and would be appropriate only if environmental harm attributable to the Rule that warranted mitigation is demonstrated.[813] On June 14, 1996, CEQ concluded that the Commission's order was fully responsive to EPA's concerns and requests and that the referral process and corresponding responses to the referral from the Commission and other agencies have successfully resolved the disagreements between EPA and the Commission.[814]

As discussed below, EPA is currently taking steps to implement a comprehensive NO_X emissions control program to ensure that emissions reductions are achieved to prevent significant transport of ozone pollution across state boundaries in the Eastern United States. OTAG is continuing to work in conjunction with EPA on this issue and intends to complete its process in the near future.

Rehearing is sought on eight categories of issues relating to the Commission's analysis of environmental issues: selection of the appropriate no-action alternative; challenges to modeling assumptions; need for mitigation; emissions standards disparity; the short-term consequences of the Rule; cost benefit analysis; socioeconomic impacts; and compliance with the Coastal Zone Management Act. For the reasons discussed below, rehearing is denied.

A. The Appropriate No-Action Alternative

The FEIS discusses several alternatives, including the alternative of instituting open access pursuant to section 211 of the FPA. The FEIS states in this regard that:

> Actions taken pursuant to section 211 and pursuant to sections 203 and 205 in merger and market-rate cases, respectively, represent a case-by-case approach to establishing open access. Absent action on the proposed rule, the Commission would continue using these authorities to require utilities to file open access tariffs and provide case-specific service, as necessary or appropriate. In addition, sections 205 and 206 charge the Commission with ensuring that purely voluntary transmission tariffs are not unduly discriminatory. Thus, if the proposed rule were not adopted, the Commission would continue to require that voluntary tariffs be upgraded to offer the Commission's current standards for non-discriminatory open access transmission services. The result of continuing the Commission's policies without the proposed rule is that the Commission would effectuate a more open transmission grid, but in a patchwork manner and at a slower pace.
>
> The case-by-case approach to achieving open access currently in use is slower and more costly, and thereby less desirable, than the generic approach set forth in the proposed rule. Thus, the no-action alternative is not a reasonable alternative to the proposed rule.[815]

Rehearing Requests

The PA Com contends that the FEIS does not adequately consider the alternative of instituting open access pursuant to section 211 of the FPA. It states that section 211 provides a means for wholesale power sellers and buyers to obtain transmission services necessary to compete in, or to reach competitive markets, and that the FEIS ignores the steady, if slow, progression to open access taking place under section 211.

Commission Conclusion

The FEIS notes that there are significant reasons for implementing open access through a rulemaking rather than the case-by-case approach of section 211. In the absence of a Commission rulemaking, the development of open access pursuant to section 211 would occur as potential transmission users file requests for such services and the Commission approves them as appropriate. Such proceedings are likely to be contested by competitors and the Commission would decide each application individually. Given the number of potential transmission users who are likely to file requests for such services, it is conceivable that this approach may require the Commission to decide a large number of such applications.[816] Thus, the case-by-case approach is likely to be much slower and more costly to implement than action by rule.

Case-by-case implementation of open access is also more likely to result in patchwork development as the policy evolves over time. It is important to develop uniform national standards to facilitate the move to open access. This approach adds certainty and facilitates development and implementation of open access in a way that would be difficult to achieve on a case-by-case basis. The development of national

[812] Letter of May 13, 1996, from Carol Browner, Administrator, EPA to Kathleen McGinty, Chair, CEQ.

[813] Order Responding to Referral to Council on Environmental Quality, 75 FERC ¶ 61,208 at 61,691–92 (1996).

[814] Letter of June 14, 1996 from Kathleen McGinty, Chair, CEQ, to Carol Browner, Administrator, EPA and Elizabeth Moler, Chair, FERC.

[815] FEIS at 2–1 and 2–2.

[816] To date, the Commission has issued six proposed orders and four final section 211 orders. *Id.* at 2–1.

standards is best done through a mechanism whereby all interested parties can participate in shaping the policy through notice and comment rulemaking. The piecemeal implementation of open access on a case-by-case basis over time, no matter how carefully conducted, is likely to result in inconsistencies and difficulty in application. Given the national nature of the electric grid and the developing open access market, case-by-case implementation is not practical nor desirable and will limit the anticipated benefits of open access.

The PA Com does not specify how the Commission fails to adequately consider the alternative of instituting open access pursuant to section 211. It is insufficient for a party to complain that an analysis is inadequate without providing specific support for its claim. As the court noted in *Northside Sanitary Landfill, Inc.* v. *Thomas*, 849 F.2d 1516, 1519–20 (D.C. Cir. 1988), *cert. denied*, 489 U.S. 1078 (1989):

In *Vermont Yankee Nuclear Power Corp.* v. *Natural Resources Defense Council, Inc.*, 435 U.S. 519, 98 S.Ct. 1197, 55 L.Ed.2d 460 (1978), then-Justice Rehnquist expressed the unanimous opinion of seven members of the Supreme Court that a party * * * has the burden of clarifying its position for the [agency]. Even though the [agency] has the statutory obligation to consider fully significant comments, ''it is still incumbent upon intervenors who wish to participate * * * to structure their participation so that it is meaningful, so that it alerts the agency to the intervenors' position and contentions.'' 435 U.S. at 553, 98 S.Ct. at 1216. Justice Rehnquist, then quoted with approval Judge Leventhal's remarks in *Portland Cement, id.*, and concluded that administrative proceedings should not be a game or a forum to engage in unjustified obstructionism by making cryptic and obscure references to matters that ''ought to be'' considered and then, after failing to do more to bring the matter to the agency's attention, seeking to have that agency determination vacated on the ground that the agency failed to consider matters forcefully presented.''

Id., at 533–54, 98 S.Ct. at 1217.

We also note that the PA Com's quarrel does not appear to be with the Commission's analysis of the section 211 alternative in any event, but rather with the underlying policy decision to implement open access through a rulemaking rather than more slowly on a case-by-case basis.

The Administrative Procedure Act authorizes agencies to establish policies by rulemaking or on a case-by-case basis. Here, the Commission has properly exercised its discretion to establish open access by rulemaking rather than in individual proceedings. The PA Com does not contest this authority or the Commission's exercise of it. Rather, its complaint goes to the underlying policy choices guiding that decision. Disagreement with an agency's policy choice is not a proper basis for a NEPA-based challenge to agency action. As the Circuit Court of Appeals for the District of Columbia (D.C. Circuit) stated in *Foundation on Economic Trends* v. *Lyng*, 817 F.2d 882, 886 (D.C. Cir. 1987) (footnote omitted) (brackets in original):

NEPA was not intended to resolve fundamental policy disputes. As the Supreme Court recently admonished, ''[t]he political process, and not NEPA, provides the appropriate forum in which to air policy disagreements.'' *Metropolitan Edison Co.* v. *People Against Nuclear Energy*, 460 U.S. 766, 777, 103 S.Ct. 1556, 1563, 75 L.Ed.2d 534 (1983) (citation omitted). A policy disagreement, at bottom, is the gravamen of appellants' complaint. In our view, ''[t]ime and resources are simply too limited for us to believe that Congress intended to extend NEPA as far as [appellant would take] it.'' *Id.* at 776, 103 S.Ct. at 1562. [817]]

Contrary to the PA Com's assertion, and regardless of the basis for that assertion, the discussion of the section 211 alternative in the FEIS satisfies the requirements of NEPA. The Supreme Court has stated that ''[t]o make an impact statement something more than an exercise in frivolous boilerplate the concept of alternatives must be bounded by some notion of feasibility.'' [818] ''Central to evaluating practicable alternatives is the determination of a project's purpose.'' [819] ''The range of alternatives that must be considered in the EIS need not extend beyond those reasonably related to the purposes of the project.'' [820] The purpose of the Rule is to implement open access in order to remedy undue discrimination and to do so on a timely basis and in a uniform manner; the Commission has determined that case-by-case implementation of open access will not satisfy that purpose.

[817] *See also* Northwest Coalition for Alternatives to Pesticides v. Lyng, 844 F.2d 588, 591 (9th Cir. 1988).

[818] Vermont Yankee Nuclear Power Corp. v. Natural Resources Defense Council, Inc., 435 U.S. 519, 551 (1978); Laguna Greenbelt, Inc. v. U.S. Department of Transportation, 42 F.3d 517, 524 (9th Cir. 1994).

[819] National Wildlife Federation v. Whistler, 27 F.3d 1341, 1345 (8th Cir. 1994).

[820] Laguna Greenbelt, *supra*, 42 F.2d at 524. In that case, involving construction of a tollroad, Laguna contended that the EIS ignored a smaller, four-lane alternative. The EIS addressed this proposal, explaining that it was rejected because a four lane highway would not meet the project's goal of reducing traffic congestion. The court found that the proposal was thus properly rejected as not reasonably related to the purposes of the project. *Id.* at 524–25.

The PA Com has proffered no reasons why the examination in the FEIS of the section 211 alternative is insufficient. We conclude that the FEIS adequately considers the alternative of instituting open access pursuant to section 211. Rehearing on this issue is denied.

B. Challenges to Modeling Assumptions

Several rehearing requests challenge the modeling assumptions used in the FEIS. These challenges are raised in support of the claim that the Commission's analysis understates the environmental impacts of the Rule. The most fundamental challenge is the PA Com's claim that computer modeling is insufficient to examine the impacts of the Rule. The PA Com and Joint Commenters suggest that the model fails to use the appropriate base case. Questions are also raised regarding specific assumptions used in the model.

In discussing these issues below, we note that although EPA raised many similar points with respect to the Commission's modeling approach in comments on the DEIS, EPA ultimately concluded that ''the FERC has conducted an adequate analysis under the National Environmental Policy Act of the environmental impacts of the open access rule under a range of possible scenarios'' and that ''[t]he FERC made a reasonable choice of models (CEUM) and made assumptions for various factors input into the model that lie within the range of reasonable assumptions.'' EPA also notes that the Commission performed the specific additional analyses that were requested in comments on the draft EIS.

As EPA points out, ''[n]aturally, there can be differences among reasonable analysts concerning the assumptions used in such an analysis.'' EPA then reiterates that it believes that assumptions used by the Commission ''lie within the reasonable range.'' It concludes that ''the FEIS provides a credible basis for understanding the possible environmental impacts of the open access rule.''

1. Appropriate Base Case

Selection of the appropriate base case was contested in the DEIS on grounds similar to those presented here. Certain commenters argued that the Commission should compare the impacts of the Rule to a no-action alternative that assumes that the Commission abandons all open access policies, not just the Rule. Some commenters went even further, suggesting that the Commission compare emission levels projected to result from the Rule against a frozen efficiency case in which other major factors—factors that would increase industry efficiency independent of the Rule—do not occur. Such factors include adoption of pro-competitive state polices and actions by utilities to undertake mutually beneficial voluntary transactions that do not require the use of open access tariffs mandated under the Rule. Commenters who advocated either a different no-action alternative or the frozen efficiency case posited that studies using those assumptions would show that the Rule will cause significantly greater NO_X emissions than those shown in the DEIS. We concluded in Order No. 888 that:

[S]taff has selected the appropriate ''no-action'' alternative. An alternative that requires the Commission to reverse all its other open access policies is simply not a ''no-action'' alternative. To the contrary, it would require decisive action running counter to the direction from the Congress in the Energy Policy Act and the needs of the marketplace and electricity consumers.

However, to ensure that the effects of the rule were analyzed fully, the FEIS did study a reference case based on the ''frozen efficiency'' case * * * Although, as described below, we believe this case to be highly unlikely, the results show that, even under this scenario, the impacts of the rule are not great and do not vary significantly from those projected by staff under the other assumptions. [821]]

Rehearing Requests

Pennsylvania PUC. The PA Com asserts that the Commission did not compare emissions levels associated with the Rule against the appropriate base case. It claims that the Commission should have used continued case-by-case evolution of open access and increased wholesale competition under FPA sections 211 and 212 as the base case instead of generic, simultaneous, nationwide open access as mandated by Order No. 888. Put differently, the PA Com claims that the appropriate base case is the evolution of competition and open access without the intervention of Order No. 888. The PA Com concludes that by using the improper base case the FEIS ignores evidence of significant NO_X increases resulting from the Rule, which affects the ability of Pennsylvania to meet the mandates of the Clean Air Act.

Joint Commenters. The Joint Commenters maintain that the FEIS uses an inappropriate no-action alternative as a basis for analysis. [822] The gist of its argument is that the Commission must acknowledge the policy initiative of which it contends Order No. 888 is only one part. It claims that the Commission ignores the fact that, whether competition is pursued through Order No. 888 or on a case-by-case basis, implementation of open access is a major programmatic policy choice the environmental impacts of which must be addressed. It contends that by using case-by-case implementation as the no-action alternative, the Commission effectively defines away most of the impacts of the Rule.

In short, the Joint Commenters claim that by defining the no-action alternative as implementation of the open access program over a longer period of time through case-by-case action, the Commission did not fully examine the potential impacts of Order No. 888. It states that if the effects of Order No. 888 are defined to include only those that result from the timing difference between implementation of open access through case-by-case decisions and open access pursuant to a generic rule, it is virtually a foregone conclusion that most of the potentially adverse environmental effects of the Commission's open access policies will not be identified.

The Joint Commenters concur that the frozen efficiency case analyzed in the FEIS is a proper starting place for an acceptable NEPA review. It faults the discussion of the frozen efficiency case, however, as failing to provide important information needed to allow parties to evaluate the analysis. The Joint Commenters complain that the analysis does not include the model outputs which demonstrate the most severe environmental effects; this, they claim, makes it impossible to verify the results or analyze the factors contributing to the effects shown.

The Joint Commenters state that in addition to omitting the modeling outputs for the most environmentally relevant cases, the FEIS does not contain air quality modeling of the scenarios that show the greatest emissions increases. It claims that the Urban Airshed Model (UAM–V) examines only the incremental impacts of the Competition-Favors-Coal Scenario as compared with the High-Price-Differential Base Case, the same analysis presented in the DEIS. The Joint Commenters stress that EPA in its comments on the DEIS noted that the results shown for this case (an emissions decrease) is illogical and should be explained. It states that without modeling the emissions changes associated with the Competition-Favors-Coal Scenario over the frozen efficiency base case, the FEIS provides no indication of the seriousness of the environmental harm from potential emissions increases caused by FERC's initiatives. The Joint Commenters also claim that the expanded transmission analysis used in the FEIS is unduly conservative.

Commission Conclusion

The Commission continues to believe that the base cases and scenarios used in the DEIS are most appropriate for studying the effects of the Rule. Nonetheless, to ensure that the effects of the Rule were analyzed fully, the FEIS also examined a frozen efficiency case that uses a combination of assumptions most likely to show significant increases in emissions.

We did this despite our belief that it is inaccurate to attribute all efficiency improvements in the industry to Order No. 888 or even to federal actions of all kinds. In fact, as noted in the FEIS, the frozen efficiency case is far more extreme in its assumptions than would be reasonable for a no-further-Commission-action case because it presumes that industry and state regulators also cease all changes toward a more competitive industry. However, the frozen efficiency case is useful as a sensitivity analysis because it reflects an extreme bound on any separate no-further-Commission-action case. [823] *A fortiori* the impact actually to be expected from the Rule must be less than that determined using the frozen efficiency case.

We believe that the frozen efficiency analysis is highly implausible because its represents a world in which: (1) the Commission reverses current pro-competitive transmission policies (inconsistent with congressional mandates under EPAct); (2) states cease to adopt programs to improve industry efficiency; and (3) electric companies cease to improve operation or to enter into mutually beneficial transactions.

The Joint Commenters agree that the frozen efficiency analysis constitutes a valid NEPA review. That issue, therefore, is not in dispute. It objects that the FEIS does not include the model outputs for the sensitivity cases which demonstrate the most severe environmental effects, and that it is therefore impossible to verify the results or analyze the factors contributing to the effects shown.

The Joint Commenters' assertion is incorrect. Appendix K of the FEIS sets forth tables demonstrating the results of

[821] FERC Stats. & Regs. at 31,863; *mimeo* at 665–66 (footnote omitted).

[822] Although cast as use of an inappropriate ''no action alternative'', the Joint Commenters' point goes to the appropriateness of the base case used in the analysis.

[823] This analysis is described as a sensitivity analysis because it examines how projected air emissions might change if key assumptions in the analysis are altered.

the model runs for the sensitivity analysis. These tables provide adequate documentation to analyze and verify the conclusions reached in the FEIS. We note also that the Joint Commenters have not requested specific model outputs that it claims are lacking. The Commission will make available information used in the study that Joint Commenters or anyone else identifies as not being provided.

As to the claim raised by the PA Com, it appears to be mistaken regarding the base case actually used in the FEIS. Contrary to what the PA Com states, the base cases do include continuing case-by-case actions under section 211 and the Commission's open access policy.

2. Challenge to the Use of Computer Modeling

The Commission's intent to use computer modeling in the identification and evaluation of the impacts of the Rule has been clear since the Commission decided to prepare an EIS. The DEIS and FEIS explain the computer modeling techniques used in the analysis in great detail.

For example, the DEIS and FEIS explain that the Coal and Electric Utilities Model (CEUM) was selected for the analysis because it is the best tested, most widely used national-level model available. [824] CEUM is a forecasting model that incorporates virtually all coal and electric utility market activities—ranging from mining, transportation, and blending of coal to power plant and system dispatching, transmission, and new capacity construction. It also examines the impact of changes in factors such as plant availabilities, heat rates, planning reserve margins, and transmission costs. CEUM has been used extensively by, among others, EPA and DOE.

CEUM models the contiguous United States as 45 separate demand regions. It possesses a supply component which models key coal supply regions and coal transportation networks in great detail. It also incorporates constraints on long-term coal supplies, power plant emission limitations, national emission caps (*e.g.*, acid rain requirements of Title IV of the Clean Air Act Amendments of 1990), coal transportation capacity, electric transmission capacity, and power plant construction plans.

The DEIS and FEIS explain that to analyze the Rule, assumptions as to factors such as electricity demand growth rates, oil and gas prices, and planning reserve margins were developed and incorporated into the model. Factors such as existing patterns of transmission capacity and costs were also analyzed and incorporated into the model.

Once the necessary information and assumptions were incorporated into CEUM, model runs were conducted to ensure that the projections closely match actual experience for a selected year, in this case 1993. These runs used the information prepared for the base cases together with other inputs (*e.g.*, electricity demand) for the historical year. The purpose of this calibration process was to ensure that the model replicates historical experience. After the model was calibrated, it was run for each of the base cases, and then for each of the Rule scenarios for selected time periods.

To examine the impact of the Rule on regional attainment of ozone standards, additional air quality modeling was conducted using the UAM–V. UAM-V is a three-dimensional photochemical grid model that simulates the physical and chemical processes in the atmosphere that affect pollutant concentrations. It tracks emissions both geographically according to preset weather patterns and chemically over time. The UAM–V was used to create detailed air quality analyses for cases that might potentially create additional impacts from NO_X transport and ozone in the Northeast.

Rehearing Requests

The PA Com challenges the ability of computer modeling to simulate the effects of the Rule. It states that computer modeling is an attempt to reflect an approximation of reality that uses systems of linear equations, and that the airborne transport of pollutants in the atmosphere and the North American electric transmission grid are extremely large, complex nonlinear systems.[825]

The PA Com's challenge to the use of computer modeling also turns on the observation that models produce results that are dependent on the inputs and assumptions used in the models. The specific challenges to the inputs and assumptions used in the model are discussed separately below.

Commission Conclusion

We note first that computer models are the only available means of analysis that incorporate the range of factors that influence engineering and economic choices in the electric power industry, and the atmospheric chemistry and weather patterns that influence downstream air quality. We are mindful of the limitations of models, but the alternative of using no model at all—and hence making no analytic attempt to capture the complex economic and environmental factors—did not appear reasonable.

The PA Com does not explain how the Commission should otherwise simulate the effects of the Rule. Computer modeling may not be a perfect tool, but it is the best existing mode of analysis for this type of effort. The PA Com cannot merely assert that such modeling is inadequate. As the court noted in a similar context in *City of Los Angeles* v. *National Highway Traffic Safety Administration*, 912 F.2d 478, 488 (D.C. Cir. 1990), *overruled in part on other grounds, Florida Audubon Society* v. *Bentsen*, 94 F.3d 658 (D.C. Cir. 1996):

> Petitioners call for more ''analysis,'' but do not specify what they see as lacking or how ''analysis'' could supply the want. At some point—here after a seemingly full treatment—the agency must make a judgment. We discern no more from petitioners' argument than that they disagree with that judgment. Even were we to share their view of the matter, that would not be a sufficient basis for overturning the agency's decision.

Quoting *Portland Cement Ass'n* v. *Ruckelshaus*, 486 F.2d 375, 394 (D.C. Cir. 1973), *cert. denied sub nom. Portland Cement Ass'n* v. *Administrator, EPA*, 417 U.S. 921, 94 S.Ct. 2628, 41 L.Ed.2d 226 (1974), the court in *Northside Sanitary Landfill, Inc.* v. *Thomas*, 849 F.2d 1516, 1519 (D.C. Cir. 1988), *cert. denied*, 489 U.S. 1078 (1989), stated in like manner that:

> [C]omments must be significant enough to step over a threshold requirement of materiality before any lack of agency response or consideration becomes of concern. *The comment cannot merely state that a particular mistake was made * * *; it must show why the mistake was of possible*

[824] DEIS at 3–2 through 3–5; FEIS at 3–2 through 3–5.

[825] The PUC appears to base its rehearing comments on the DEIS; the points it asserts on rehearing ignore extensive responses to these comments in the FEIS. For example, the FEIS responds to the following specific points that are now raised by the PUC on rehearing: Impact of the rule on Pennsylvania coal production (FEIS at J–22); impact on reliability (FEIS at J–26); impact on stranded benefits (FEIS at J–30); impact of assumed increased volume of transmission transactions (FEIS at J–39); claim that the analysis must consider impact of Group II boiler rule and Phase III of the MOU (FEIS at J–49); claim that FEIS makes conclusory statements (FEIS at J–60); claim that heat rate assumptions are optimistic (FEIS at J–63); claim that transmission usage prices are circular (FEIS at J–65); claim that availabilities are speculative (FEIS at J–67); claim that reserve margins are unlikely to fall as far as the FEIS assumes (FEIS at J–68); concerns about choice of linear modeling (FEIS at J–73); concerns about differing emission standards in Pennsylvania and West Virginia (FEIS at J–92); claim that the Rule is inconsistent with Title I of the Clean Air Act (FEIS at J–97).

significance in the results [the agency reaches]. (Emphasis in original).

The FEIS explains the Commission's conclusion that the environmental analysis of Order No. 888 is best conducted using the CEUM and UAM–V computer models. The PA Com cannot merely state that the use of such models is inappropriate. It must explain why this is so and what alternative method of analysis should be used. This it has not done. The request for rehearing is denied.

3. Transmission Assumptions

The FEIS recognizes the interdependence of interregional electric transmission transactions; accordingly, non-simultaneous interregional transfer capabilities estimated by the North American Electricity Reliability Council (NERC) were reduced for use in the model (*see* FEIS section 3.4.2). The analysis also considers the impact of the Rule on interregional transfers (*see* FEIS Tables 5–13 and 5–14), and the impact of changes in transmission capacity through sensitivity analysis.[826]

Rehearing Requests

The PA Com asserts that transmission usage in the FEIS is based on assumptions which are indeterminate to some degree. It states that historical interregional power transfers are used to estimate future transmission capabilities and capacity, and that while historical interregional electric transmission transactions have been large and complex, under the Rule the level of transactions will increase enormously. The PA Com claims that almost every time a new major interregional electric transmission transaction has occurred, there have been unpredictable flows of electricity in other regions that might be a thousand miles away. It concludes that relatively small changes in transmission flows can and have produced large harmonic transients and instabilities on the power grid.

The PA Com also contends that the relationship between the transmission usage price and the price of transmission service is unclear. It states that the development of the usage price seems circular, at least in part. It notes that model inputs were changed until the usage price coincided with an estimate of historical costs. The PA Com requests clarification of the development of the usage price assumption.

Commission Conclusion

The PA Com does not appear to understand the way the transmission usage price functioned in the analysis.[827] As explained in the FEIS, the CEUM model is annual and regional: it models a single year at a time using regions approximately the size of a state or large regions within a state.[828] Transmission in the model is represented as movement of power from one region to another. The model attempts to satisfy the demand for electricity at lowest cost—if there were no limitations on the movement of power from one region to another, the model would always generate power at the cheapest source and move that power to meet the demand. This result would clearly be unrealistic, since sources of power are limited in their ability to reach demand by limitations in the intervening transmission network. The transmission network in CEUM is represented primarily by the limitations that the transmission grid places on the ability of power to move freely to meet demand.

To use CEUM to provide a reasonable representation of transmission requires balancing the different ways in which the transmission system imposes limits on the movement of power. Flows on links between regions are limited by three general parameters in the model: losses, variable costs, and constraints on the quantity of capacity or energy that can be transferred. Losses are generally small, and are typically kept fixed from one model run to the next. Simulating transmission limits is largely a matter of balancing variable costs and quantity limits. True variable costs are usually assumed to be small, reflecting the low variable cost of operating the transmission system. Basic quantity limits are usually developed from NERC sources or other studies of the limits imposed by the physical operation of the transmission system.

However, such limits do not always provide an adequate picture of current patterns of generation and transmission in the electric utility system. Movement of power from low cost sources is limited not only by the physical constraints of the transmission system, but also by institutional impediments such as lack of access to needed transmission. As a result, in a model like CEUM, where flows are based on minimizing costs subject to physical constraints, the amount of power flowing from lost-cost sources of generation is typically overestimated.

The FEIS explains that there are two primary ways to address this difficulty when calibrating the model to represent historical power flows. One is to impose further limits on the quantity of power transferred within the model. The other is to raise the variable cost to simulate the effect of observed barriers to power flows between regions. The second approach was used by developing a ''usage price'' to raise the variable cost barriers in CEUM and supplement basic quantity limits derived from NERC estimates. This approach was taken because of its nexus to the primary effect of the Rule on transmission activities. The primary effect of the Rule on transmission will be to increase the ability of transmission users to gain access to transmission service and to permit users to develop flexible ways for buyers and sellers to use the transmission system efficiently. The primary effect is thus to remove institutional barriers to the use of the transmission system—in effect to reduce the transaction costs, or usage price, faced by those seeking access to transmission. Thus, the model was calibrated by selecting an initial set of usage prices and adjusting those prices until the model provided an accurate representation of historical generation and transmission patterns.

Usage prices (in mills per kWh) were developed by running CEUM for a historical period (1993). Starting from initial estimates of usage prices between CEUM regions, the model was run using historical inputs for 1993; the outputs from these runs were compared with the historical pattern of generation and transmission for that year. Usage prices were then adjusted until the pattern projected by the model was consistent with the observed historical pattern. The final adjusted prices were then used as the current usage prices.

Two rules were used to set the initial usage price estimates:

(1) For closely coordinated (*i.e.*, tight) pools, no separate usage price was assumed. This is consistent with the principle embodied in many pools that transmission

[826] FEIS at 3–8 through 3–11.

[827] As explained in the FEIS at 3–13 through 3–15 and as discussed below, the movement of power from low cost sources is limited not only by the physical constraints of the transmission system, but also by institutional impediments such as lack of access to needed transmission. As a result, in a model like that used in the EIS, where flows are based on minimizing costs subject to physical constraints, the model will typically overestimate the amount of power flowing from low-cost sources of generation. The Commission chose to address this by developing a ''usage price'' to raise the variable cost to simulate the effect of observed barriers to power flows between regions. The usage price is a proxy for transmission barriers, not an attempt to estimate or model an actual transmission price. The usage price was calibrated to produce actual historical *flows* of electricity, not *costs* of transmission. As such it has almost no relationship with actual transmission prices.

[828] *Id.*

assets are to be treated as one system and used to minimize variable costs. Any allocation of the cost of service associated with transmission assets is typically treated as a fixed cost.

(2) Separate transmission costs are commonly applied in loosely configured pools. In many cases, these separate costs are derived on a MW-mile basis. Because the number of systems that have to be traversed within a loosely configured pool is generally small, the transmission usage price for areas with loosely configured pools were set to a small initial value (1 to 2 mills/kWh). Transmission across NERC regions may require traversing many utility systems, and for modeling purposes a charge of about 3 mills/kWh was assumed.

Applying this method required several runs of CEUM. Usage price changes were typically downward in areas where the initial prices were set at 3 mills per kWh, and prices after adjustment remained within the range of the initial usage prices. As a result, estimates of the current usage price varied from region to region after calibration, but generally fell within the range of 1 to 3 mills per kWh.

Thus, the concerns expressed by the PA Com were either considered in the FEIS, or are based on a misunderstanding of the method used.

4. Plant Availabilities and Heat Rates

The FEIS explains that power plant availability is the percentage of time that a generating unit is available to provide electricity to the grid, and that availability estimates for coal plants have an important effect on projected base case emissions because those estimates determine the amount of future generation expected from existing power plants.[829]

The base cases assume that average fossil-fuel plant availability rises to 85 percent by 2005 and then remains constant through 2010. This assumption reflects continuing efforts by utilities to improve plant availability. Between 1984 and 1993, coal plant availability increased five percent to nearly 81 percent. This trend is projected to continue through 2005 as electric generators respond to competitive pressures and opportunities extant without the Rule.

The FEIS explains that in the Competition-Favors-Coal Scenario, plant availabilities are assumed to reach 90 percent (as opposed to 85 percent in the base cases and other Rule scenarios) because competition is projected to lead to greater operational efficiency in generation markets. It notes that some older coal plants are not likely to reach this level without substantial capital investment. However, since 90 percent availability is achievable for many plants, this figure was selected as an upper bound to illustrate how much existing plants may be able to run if generation owners focus on meeting competition through greater use of coal plants.

The FEIS also explains that the base cases assume some deterioration in heat rates between life extension programs. In the Competition-Favors-Coal Scenario, existing generating plants are assumed to be better maintained so that there is no deterioration of heat rates between life extension programs. Except in the Competition-Favors-Gas Scenario, it is assumed that new combined cycle natural gas plants sustain existing heat rates (rather than improving as the next generation of gas technology comes on line). These assumptions reflect the fact that industry has put more effort into making better use of existing (disproportionately coal) plants rather than into improving the performance of new (almost entirely gas) plants.

Rehearing Requests

The PA Com challenges the plant availability assumptions used in the FEIS. It notes that the analysis assumes that generation plant availability will rise to 85 percent and that the Competition-Favors-Coal Scenario assumes that generation plant availability will rise to 90 percent by the year 2005. The PA Com states that although historical trends indicate that plant availability might increase, in reality as availability goes up it becomes increasingly difficult to obtain further improvements.

The PA Com contends that increasing availability to 85 percent would be surprising; an increase to 90 percent would be astonishing. It states that such increases would require a number of simultaneous technical advances, the likelihood of which are speculative. The PA Com argues that utilities in competition with each other may be less willing to fund and participate in cooperative research that leads to technical advances. The PA Com notes that maintenance staffs are being reduced as a result of cost reduction programs and that plant availability might decline as maintenance is deferred.

The PA Com also contends that the assumption in the Competition-Favors-Coal Scenario that heat rates do not degrade (go up) over time may be optimistic. It concedes that technological advances have produced dramatic improvements in heat rates, but states that it is unclear if this improvement is sufficient to overcome losses caused by backfitting emission control equipment. The PA Com notes that coal-fired generating stations in Pennsylvania have been required to install emission control equipment and that efficiency has been reduced in some cases, degrading the heat rate. It states that some coal stations have installed sulfur dioxide (SO_2) scrubbers which can reduce efficiency by five percent, and that other stations may be required to install selective catalytic reduction systems for NO_x or SO_2 scrubbers.

The PA Com contends that an additional limit on heat rate improvements is the age of generating stations and the fact that heat rates decline as stations age. It posits that this decline may be greater than the improvements that can be gained through technological advances.

Commission Conclusion

The PA Com's argument fails to consider the discussion of this issue in the FEIS.[830] Briefly, higher availabilities for coal plants were assumed in order to provide a scenario that was extremely favorable to the use of coal in existing facilities and hence a scenario that was most likely to have a larger environmental impact. The fact that some coal plants are able to maintain 90 percent availability is sufficient grounds for considering such a case, especially where the purpose of the assumption is to establish a reasonable range of potential environmental outcomes from the Rule.

With regard to the heat rate assumptions, the PA Com does not appear to understand how the assumptions functioned in the analysis. First, the factors it mentions (*e.g.*, efficiency reductions resulting from the addition of scrubber technology) are already considered in the CEUM model. Second, the CEUM does assume that heat rates degrade over time in the base cases. The assumption that they do not degrade in the Competition-Favors-Coal Scenario was made to simulate the relative improvement that might be achieved through potential effects of the Rule when competition is favorable to coal. As with certain other modeling assumptions challenged by the PA Com on rehearing, the heat rate assumptions used by the Commission are more conservative than those urged by the PA Com and thus demonstrate greater impacts from the Rule than would be the case using the assumptions urged by the PA Com.

[829] *Id.* at 3–18.

[830] Id. at J–63 and J–67.

5. Reserve Margins

The FEIS discusses the assumptions regarding planning reserve margins and their use in the model.[831] It states that planning reserve margins influence the amount of new capacity built and the mix of gas versus coal fired generation projected in CEUM. In particular, lower reserve margins tend to result in the construction of less capacity (typically, fewer gas-fired turbines and combined cycle units) and a somewhat greater utilization of existing coal units.

Generally, individual utilities set their reserve margins to comply with a technical standard established by the NERC sub-region. Typically, the NERC sub-region might determine that a one day in 10 years loss of load probability (LOLP) is the appropriate standard. Individual utilities within the sub-region would determine their reserve planning margin to be consistent with this standard after accounting for tie capabilities. NERC sub-regional studies are performed periodically to determine whether the reliability standard is being satisfied for the planning horizon given planned capacity additions. The tie capability between the sub-region and other regions is accounted for in reliability studies at the NERC sub-regional level.

The FEIS notes that in recent years, reserve margins typically have been revised downwards, although the planning standard itself (most commonly the one day in 10 years LOLP) has not been changed. Three reasons support the downward revision in reserve margins: (1) An expected improvement in unit availability; (2) anticipated shifts in utility load shape towards a lower load factor; and (3) an increase in the number of generating units.

FEIS Table 3–4 summarizes the reserve criteria and associated planning reserve margins that have been derived from the most recent annual planning documents prepared by the reliability councils. It states that a review of current planning documents shows that utilities expect planning reserve margins to decline over time. One factor identified as contributing to this decline is the expectation that availability will improve appreciably as utilities are subject to performance-based regulation and experience greater competition.

Additionally, some utilities have revised their planning reserve margins to account for ties in other regions. In some cases, utilities have updated their planning reserve margin calculation to reflect current estimates of customer willingness to pay for increase reliability.

Based upon a review of utility expectations, the FEIS concludes that an appropriate base case assumption is for planning reserve margins to decline by 2005 to the lower end of the applicable ranges set forth in FEIS Table 3–4.

Rehearing Requests

The PA Com challenges the reserve margin assumptions used in the model. It asserts that the assumption that reserve margins will fall to fifteen percent by 2000 and (in one scenario) to thirteen percent by 2005 is based in part upon the assumption of increased generation plant availability across the board. The PA Com notes that this increase in availability might not occur. It states that as wholesale transactions increase under open access, some, but not most, utilities will be able to reduce reserve margins and still maintain reliability. The PA Com asserts that many utilities cannot reduce reserve margins because available transmission capacity between regions is already being utilized to the maximum extent possible. It concludes that reserve margins for certain individual utilities could decline, but this alone would not reduce required reserve margins for all utilities to the levels that are assumed in the model.

Commission Conclusion

The reserve margins used in the base cases were set using current utility plans and trends in the industry. Reserve margins for the competition scenarios were set slightly lower, reflecting the potential for decline in a more open competitive environment. The PA Com acknowledges the potential decline, but claims that not all utilities will be able to reduce reserve margins to the levels assumed. However, the FEIS addresses such differences by using different regional assumptions about reserve margins and different reserve margins in each region. The PA Com's concern is therefore without basis.

6. Northeast MOU

The FEIS assumes that power plants in the Northeast Ozone Transport Region (OTR) will comply with Phase II of the Northeast Memorandum of Understanding (MOU). The MOU establishes NO_X tonnage limits during the five-month ozone season (May-September) for electric generating and large industrial services and allows for emissions trading.[832] The FEIS states that compliance with Phase III of the MOU was not assumed since its implementation is optional, depending on final attainment status with regard to Clean Air Act requirements.

Rehearing Requests

The PA Com states that the base cases and scenarios assume that no NO_X controls will be required for Title IV group II boilers, that phase II of the MOU will be implemented, and that no additional requirements will be imposed. The PA Com contends that phase III of the MOU might be implemented, and that if this occurs and upwind generation is not required to control ozone precursors, cleaner generation in the Northeast may be displaced by increased generation from outside the OTR.

Commission Conclusion

In essence, the PA Com appears to be raising an emissions disparity argument rather than posing a challenge to the modeling assumptions used in the FEIS. The emissions disparity argument is addressed below.

7. Natural Gas Prices

Average wellhead natural gas prices for the High-Price-Differential Base Case were based on a recent forecast of natural gas acquisition prices by Wharton Econometric Forecasting Associates (WEFA).[833] This forecast projected at that time that natural gas prices would increase in real terms (1994 dollars) to $1.83 per MMBtu by 2000, and rise to $2.42 per MMBtu by 2010. The forecast was selected as representative of a number of natural gas price forecasts that were made during that time.

CEUM requires delivered, not wellhead or acquisition, prices as an input. Delivered natural gas prices for each Census region were derived from the weighted average transportation mark-ups reported by the Energy Information Administration (EIA) in *Natural Gas Monthly* for each Census region. The *Natural Gas Monthly* provides a consistent historical series of wellhead and delivered prices for calculating historical transportation margins. These margins were assumed to remain constant throughout the forecast period.

In the Constant-Price-Differential Base Case, delivered gas prices were assumed to equal current delivered spot prices in each region. To maintain a constant gas price relative to coal, these prices were assumed to decline from current levels

[831] *Id.* at 3–16 and 3–17. Table 3–4 is found on page 3–17.

[832] *Id.* at 3–25.

[833] *Id.* at 3–5 through 3–8.

at the same rate as coal prices decline in CEUM.[834]

Rehearing Requests

The Joint Commenters assert that the fuel-price assumptions used in the model unduly favor the use of natural gas as a fuel and appear to understate adverse effects.

In particular, the Joint Commenters claim that the two alternative fuel-price cases use the same coal price assumptions. It states that the Competition-Favors-Coal Scenario is supposed to demonstrate the effects of economic assumptions that favor coal, but that this case actually uses price assumptions that reflect the lowest natural gas price of the projections cited in the FEIS. It states that the FEIS should have used projections less favorable to natural gas: for example, $2.51 per MMBtu in 2000 (Gas Research Institute) and $3.37 per MMBtu in 2010 (Energy Information Administration). Put differently, a more appropriate Competition-Favors-Coal Scenario would have used the projected highest reasonable natural gas prices relied on in the FEIS.

The Joint Commenters then claim that the Constant-Price-Differential Base Case is based on gas price assumptions that are far below the projected prices cited in the FEIS.[835] According to the Joint Commenters, this case assumes natural gas prices of $1.67 per MMBtu in 2000 and $1.57 per MMBtu in 2010. It asserts that these estimates are approximately 10 and 54 percent lower in years 2005 and 2010, respectively, than the lowest forecasts cited. A more appropriate Competition-Favors-Gas Scenario would have used the WEFA forecasts that contain the lowest reasonable projected gas prices.

Commission Conclusion

The claim that the assumptions unduly favor natural gas prices is incorrect. First, the assumption that lower gas prices will reflect favorably the environmental effects of the Rule is not valid. The impact of the Rule when gas prices are constant relative to coal is very close to the impact when gas prices are high relative to coal.[836] For example, the impact on total NO_X emissions in 2005 is higher when gas prices are constant relative to coal than when gas prices are high relative to coal (88,000 tons for the Constant-Price-Differential Base Case versus 55,000 tons for the High-Price-Differential Base Case).[837]

Second, the two price series were selected to give a range of variation in emissions that reflect differences in the price of gas relative to coal, rather than to project a ''correct'' natural gas price. As discussed in the FEIS, the Constant-Price-Differential Base Case reflects a continuation of the historical relationship between gas and coal prices over the past 10 years. Appendix G shows how forecasts over this period have consistently overestimated the price of gas relative to coal. It is therefore reasonable to consider the Constant-Price-Differential Base Case as one side of a reasonable range.

The prices selected for the other side of the reasonable range of gas prices relative to coal (the High-Price-Differential Base Case) were based on current forecasts at the time of the analysis. There were two primary reasons for selecting a lower gas price from the range of existing forecasts. First, the CEUM coal price forecast is determined within the model and could not be changed as an input. This coal price forecast was lower than the coal prices assumed in other forecasts. By picking a gas price forecast at the lower end of the range of current forecasts, and combining this forecast with the lower coal prices forecasts in CEUM, the analysis assumed a typical price of natural gas relative to coal.

Second, at the time the analysis was conducted, all major forecasting organizations stated that they expected their gas price forecasts to be lower. However, these organizations did not complete their forecasts for several months. Since the available forecasts were up to a year old, there was reason to believe the forecasts overstated the current thinking among forecasters regarding future natural gas prices. This reason was confirmed by the forecasts that appeared around the time the analysis was completed. For example, the forecast for the wellhead price of natural gas in the year 2010 from the EIA published in January 1996 was $2.10 per million Btu, 15 percent below the forecast of $2.42 assumed for the High-Price-Differential Base Case in the FEIS.

8. Expanded Transmission Analysis

Several commenters on the DEIS expressed concern that increases in transmission capacity resulting from open access might increase generation levels and thus air pollution. In response, the FEIS examined scenarios that increased transmission capacity substantially beyond current levels—including increases that the Commission believed would far exceed any transmission capacity increases that might occur as a result of the Rule. This analysis found that postulated increases in transmission do not affect emissions attributable to the Rule. The Commission also found that issues regarding enhancement of existing lines are more complex, and that this is due in part to the fact that state-level siting issues, the principal barrier to major increases in the transmission grid, are unaffected by the Rule. While competition will lead to improved efficiencies in generation, transmission will remain a regulated monopoly function. The Rule will reduce barriers to access, but will not open the transmission system to direct competition. Thus, the Commission concluded that the competitive effects of the Rule on transmission will be relatively small.[838]

Rehearing Requests

The Joint Commenters claim that the expanded transmission analysis is unduly conservative. It states that the Commission increased peak transmission usage from 75 percent of first contingency total transfer capability (FCTTC) to 105 percent of FCTTC, and that this expanded transmission analysis represent minimal actual expansions, the most extreme of which barely increases FCTTC above current levels by the year 2010. The Joint Commenters claim that the Commission should have examined additional expansion potential in those analyses that more accurately demonstrate the effects of transmission expansion.

Commission Conclusion

The Joint Commenters' claim that the expanded transmission analysis is inadequate is based on the premise that the FEIS used the wrong assumptions in developing transmission capacity. Joint Commenters contend that 100 percent of the FCTTC should have been used in CEUM. We believe that the use of 75 percent of this capacity to reflect annual capability is the appropriate level for modeling purposes. This reduction factor is necessary because the capability must be simultaneous systemwide capability and it must be sustainable. The FCTTC is a non-simultaneous ''snapshot'' transmission capability. The total simultaneous transfer capability is not accurately represented by adding together the

[834] *Id.* at 3–7 through 3–8.

[835] The Joint Commenters claims as to the Constant-Price-Differential Base Case are probably meant as a reference to the Competition-Favors-Gas Scenario.

[836] FEIS Chapter 6.

[837] *Id.* at Table 6–19 (page 6–23) and Table 5–18 (page 5–16), respectively.

[838] FERC Stats. & Regs. at 31,872 n.974; *mimeo* at 691–92 n.974.

maximum transfer capability of each line in the system. The transmission system is a system. Loading on one line affects loading capability on all other lines in the system. This is especially true if the calculation is for capability over an extended period of time, as is the case with the FEIS, which uses transfer capability over one year. ''Derating'' as it has been called, is a reasonable way to represent the fact that a transmission system is capable of carrying less than the sum of the capabilities of the individual lines. Further, when modeling, if the model is calibrated so that the system is carrying actual historical flows—no matter what factor is used—the system will be carrying at or near its maximum capacity at constrained points which are the only points on the system where increased capacity would produce increased flows. As a result, increasing the transfer capability factor by up to 40 percent, as is done in the sensitivity analyses in Chapter 6 of the FEIS, represents a large change in the capability and use of the transmission system. Moreover, we note that this methodology has been used in previous CEUM analysis, where it was subject to review by electric utility experts.[839] For these reasons, the Joint Commenters' criticisms are invalid.[840]

The Joint Commenters challenge the assumptions used in the Commission's expanded transmission analysis as ''unduly conservative'' and ''represent[ing] minimal actual expansions.'' Joint Commenters fail to explain in what respect they deem the expanded transmission analysis to be inadequate. They fail even to respond to the matters discussed by the Commission with regard to this issue in Order No. 888.

As we noted above in the discussion of the PA Com's argument that the Commission failed adequately to consider the alternative of instituting open access pursuant to section 211 of the FPA, it is insufficient for a party to complain that an analysis is inadequate without providing specifics.

C. Mitigation

The FEIS and Order No. 888 extensively assess the need for mitigation and discuss potential mitigation measures, including proposals advanced by commenters.[841] This discussion is perhaps best summarized by the conclusion to Chapter 7 of the FEIS, which states that:

This FEIS shows that the proposed rule is expected to slightly increase or slightly decrease total future NO_X emissions, depending on whether competitive conditions in the electric industry favor natural gas or coal. The insistence of commenters that the Commission adopt and implement mitigation measures is based on significantly overstated assumptions regarding the contribution of the proposed rule to the existing environmental problems. The analysis presented in Chapter 6 establishes that overstated assumptions about the impact of the proposed rule are simply wrong.

Nonetheless, in light of the importance of this issue, we have examined potential mitigation measures in detail, including those proposed by commenters, to ensure that environmental consequences of the rule have been fully and fairly evaluated. We do not believe mitigation should be undertaken in this rule because:

Any mitigation measures the Commission might undertake are not justified by the small impacts of the rule, which impacts are as likely to be beneficial as they are to be harmful;

The impacts of the proposed rule are dwarfed by the far larger ozone and NO_X emission issues that either have nothing to do with the electric industry or will be unchanged by the rule or the larger open access program. We believe that it would be ineffective to address the NO_X and ozone issues in a piecemeal way;

The NO_X issue is part of a long-standing, difficult set of inter-regional environmental issues. Representatives of many interests in both the Northeast and the Midwest have invested substantial efforts towards finding acceptable solutions through the OTAG process. Any mitigation the Commission might undertake could usurp EPA's mandate under the Clean Air Act and undermine progress towards comprehensive solutions sought by OTAG. This is not justified by impacts that are small and just as likely to be positive.

We do not agree that the frozen efficiency reference case should be substituted for the EIS base cases or that competitive forces will favor coal over the next 15 years. But even accepting those assumptions, emissions attributable to the rule are relatively small until well after the turn of the century. So, even accepting such assumptions, the staff believes it would be unreasonable for the Commission to adopt mitigation requirements as part of the final rule; to do so would be tantamount to assuming that EPA and OTAG will not implement reasonable control measures in the next ten to 15 years;

The Federal Power Act and NEPA, either singly or conjointly, do not authorize the Commission to adopt and implement the proposed mitigation measures. The Commission does not possess (and has no mandate to possess) expertise on the extremely difficult issues involved in atmospheric chemistry and transport. It is fundamentally a economic regulatory agency. As a result, any mitigation measures the Commission undertook would be based on less-than-ideal information and analysis. It is unreasonable for the Commission to attempt such mitigation given the impacts found in this FEIS. This is especially true in light of the substantial additional research that EPA and OTAG are undertaking on the basic nature of the problem;

Some suggested mitigation measures that might work at the transaction level would undermine the purpose of the rule. There is no justification for endangering the substantial benefits projected from the rule to mitigate a problem that might not exist and that is, in any case, likely to be small.[842]

The FEIS goes on to note that the long-term existence of a significant ozone nonattainment problem in parts of the country has led to the development of mechanisms to address this issue. It states that any incremental increases in NO_X emissions that may result from the Rule can be addressed within this existing framework. In particular:

The Clean Air Act authorizes EPA to establish transport regions that are charged with assessing the degree of interstate transport of pollutants, assessing mitigation strategies, and recommending revisions to State Implementation Plans to correct the problem. The Clean Air Act specifically establishes an ozone transport region for the Northeast. The jurisdictions that comprise the OTR have developed a coordinated approach to this problem that includes adopting a regional cap on NO_X emissions.

Although the OTR process is achieving its purpose, the problem is larger than the OTR can address. As a consequence, the Ozone Transport Assessment Group has been formed which encompasses the OTR and upwind states that contribute to nonattainment. OTAG is performing extensive photochemical grid modeling of the eastern U.S. to determine ozone transport patterns and to evaluate the efficiency of various control strategies. OTAG is considering imposing a cap and trade system for NO_X emissions in a 37-state area comprised of the Northeast OTR and upwind states. If the cap and trading system becomes

[839] Edison Electric Institute, Assessment of Greenhouse Gas Emissions Policies on the Electric Utility Industry: Costs, Impacts and Opportunities, prepared by ICF Resources, January 1992.

[840] *See also* FEIS Sections 3.4.2.1 and J.7.1.

[841] The EIS and Order No. 888 examine the specific mitigation proposals advanced by the Center for Clean Air Policy, the EPA, the Joint Commenters, the Project for Sustainable FERC Energy Policy, and the Department of Energy. FEIS at 7–28 through 7–43; FERC Stats. & Regs. at 31,877–82; *mimeo* at 705–17. The Commission concluded that the mitigation measures urged by the commenters are unwarranted, and that mitigation of the Rule is not required. Of the commenters advancing specific mitigation proposals in comments on the draft EIS, only the Joint Commenters seek rehearing of Order No. 888 on environmental issues. The Joint Commenters do not take issue on rehearing with the Commission's rejection of its mitigation proposal, but rather mounts a broad attack in which it asserts that the Commission has failed to properly consider and disclose the potential environmental effects of the Rule, and that the Commission's decision that it lacks authority to implement mitigation is contrary to law.

[842] FEIS at 7–47 and 7–48.

effective it should fully mitigate NO_X emission increases, if any, attributable to open access transmission within the 37-state area. A cap and trade program is also likely to mitigate CO_2 and mercury emissions.

We believe that the cap and trading system under consideration in the OTAG process is the preferred approach to the overall NO_X emissions problem. The OTAG process brings to the table the parties that must participate in making the difficult decisions to fully resolve this problem. The OTAG process possesses the technical resources and expertise to address the difficult scientific and technical issues that must be resolved to remedy this problem. More limited approaches cannot render a satisfactory solution. We respect the expertise and the goals of the OTAG process and do not believe we can or should substitute for them in addressing this long-term national problem.[843]

Rehearing Requests

Pennsylvania PUC. The PA Com claims that the Commission has inappropriately declined to assume any responsibility for mitigating environmental impacts associated with the Rule. It states that the Commission has authority to take mitigation measures related to its regulatory actions and that the Commission can reasonably add environmental impacts to the list of factors to be weighed under the FPA's public interest standard. In this regard, it contends that the FPA grants FERC authority to place conditions on the regulation of rates and conditions of wholesale power sales and the interstate transmission of electric power as well as to order wholesale wheeling under certain circumstances.

The PA Com states that the Commission should act to minimize the likelihood of significant additional NO_X emissions by developing a mitigation plan to be implemented in conjunction with the Rule, and that FERC should use the results of the OTAG process to provide information to develop this strategy. The PA Com concludes that FERC should not require open access generically.

Vermont Department of Public Service. The Vermont Department of Public Service (VT DPS) contends that the Commission erred in failing to establish a monitoring program and a periodic reopener provision to address environmental considerations. VT DPS submits that the Commission has given inadequate consideration to the possibility that the Rule may unnecessarily exacerbate environmental impacts. It notes EPA's claim in its referral letter to the Council on Environmental Quality (CEQ) that any future NO_X increases resulting from open access would exacerbate the difficulty of accomplishing reductions in NO_X emissions.

VT DPS claims that the environmental review process has not facilitated the ability of affected parties to review all modeling assumptions. It also claims that other environmental reviews suggests more serious NO_X emission consequences of the Rule than acknowledged by the Commission.

VT DPS states that given the possibility that the FEIS conclusions may prove wrong, the Commission should take steps to permit timely reevaluation of its program. VT DPS recommends that the Commission establish an ongoing monitoring program to determine if the Rule poses an unacceptable risk to air quality. It states that a monitoring program would allow the Commission to take timely action to mitigate any unintended consequences of the Rule. The Commission should also provide for periodic reevaluation of the Rule's open access provisions and should commit to a comprehensive reevaluation of the Rule's environmental impacts every five years over the next 20 years.

New York Attorney General. The New York Attorney General (Attorney General) states that the federal government should ensure that New York and other Northeast states do not bear the burden of any increased air pollution resulting from deregulation.[844]

The Attorney General asserts that utilities in upwind states have a competitive advantage relative to Northeast utilities because they are subject to less extensive environmental controls. The Attorney General contends that deregulation may result in these plants increasing generation, thus increasing emissions that will contribute to the inability of New York and the Northeast to meet the federal ozone standard. The Attorney General claims that, regardless of the effects of the Rule, studies show that a 50 percent reduction in NO_X emissions from all sources east of the Mississippi will be necessary for New York and other Northeast states to achieve the ozone standard.

The Attorney General states that Congress has placed limits on EPA's authority to protect New York from upwind emissions, and that it is therefore essential that FERC exercise any authority it may have to mitigate the environmental effects of the Rule.

The Attorney General claims that EPA's proposal in its February 20, 1996 comments to place a cap on NO_X emissions would mitigate the effects of the Rule; it suggests basing this system on the MOU pursuant to authority residing in EPA and/or FERC. Under this proposal, a utility would be permitted to take advantage of deregulation if it simultaneously takes steps to prevent emission increases.

Joint Commenters—Overview. The Joint Commenters state that FERC has failed to consider and disclose the potential environmental effects of the Rule, and that FERC's decision that it lacks authority to implement mitigation is contrary to law.

The Joint Commenters' premise is that, despite deficiencies in the Commission's analysis which understate the effects of the Rule, the FEIS nonetheless presents data confirming that open access will have significant adverse environmental impacts. Joint Commenters posit that increased emissions from open access could seriously threaten achievement of Clean Air Act requirements and other environmental commitments. It reasons that the Commission therefore must develop and implement environmental mitigation.

The Joint Commenters begin with the assertion that the data presented in the FEIS do not support the conclusion that the effect of the Rule on air pollution will be insignificant. It claims that the Commission relied on cases that show small impacts. Joint Commenters note in this regard that EPA has determined that any increase in NO_X emissions from restructuring is unacceptable and should be remedied.

Joint Commenters then assert that FPA sections 205 and 206 require the Commission to adopt mitigation. It claims that case law supports the proposition that both NEPA and the FPA authorize FERC to mitigate the adverse environmental impacts arising from its action. Even assuming *arguendo* that it was reasonable for the Commission to reject specific proposed mitigation measures, it is unreasonable the deny the existence of authority to mitigate. The Commission should remedy this by adopting mitigation concurrent with implementation of Order No. 888.

According to Joint Commenters, the FEIS establishes that competitive electric markets will likely result in higher utilization of heavily polluting coal-fired generation. Thus, in view of EPA's statement in its referral to CEQ that any increase in NO_X emissions could seriously undermine attainment of health based standards, the FEIS

[843] *Id.* at 7–49.

[844] The New York Attorney General wrote to the Commission on May 13, 1996 expressing concern about the potential environmental effects of the Rule. Its filing does not appear to constitute a request for rehearing, but it is treated here as such.

finding that emission increases that may be as large as 315,000 tons per year are insignificant is not supported by the record.

Joint Commenters then argue that not only does the decision not to implement mitigation measures risk nonattainment of public health goals, it will fail to achieve the regulatory objective of fair and efficient bulk power competition. It contends that without concurrent environmental mitigation, the Commission will put in place a market structure that is inherently discriminatory and that arbitrarily shifts costs. It states that Order No. 888, in effect, provides a class of competitors with an undue preference subsidy. This undue preference results from the fact that the owners of coal-fired generation that are not subject to emissions regulation will be able to shift financial responsibility for their pollution to competitors in downwind regions. This discriminatory situation will distort the bulk power market and produce inefficiencies that the Commission has not addressed.[845]

Open Access Will Have Significant Adverse Impacts. The Joint Commenters state that some FEIS scenarios show that restructuring is likely to have significant adverse environmental effects. It claims that the sensitivity analyses confirm that low-cost, high-emission coal plants may increase their capacity utilization from an average of 62 percent in 1993 to 81.5 percent by 2010 and that this increase is associated with an additional 515 billion kWh of coal generation per year by 2010 above 1993 levels, assuming expanding transmission. FEIS data further indicate that 110 billion kWh of this annual increase by the year 2010 will be attributable to competition under the open access policy compared to the frozen efficiency case.

The Joint Commenters assert that the FEIS also confirms that this increase in coal-based generation will increase NO_X emissions across the 37-state OTAG region by 250,000 tons per year by 2010 (315,000 tons for the entire U.S.) and result in a cumulative NO_X emissions increase across the U.S. of 530,000 tons by 2000 and 2.7 million tons by 2010.

The Joint Commenters assert that the impacts of a 250,000 ton NO_X increase across the OTAG region are extremely significant, particularly in downwind nonattainment areas, and fly in the face of EPA's determination that any increase is unacceptable.

The Joint Commenters contend that the Commission understates the significance of these numbers by emphasizing percentages and using national figures. According to Joint Commenters, the FEIS demonstrates that regional increases in NO_X include a seven percent increase in the East North Central region, 10 percent in the Mountain region and 26 percent in the Pacific regions. These references are to emissions in 2005. The percentages in the year 2010 are approximately five percent nationally, rather than the three percent discussed in Order No. 888.

The Joint Commenters state that the FEIS also shows that increased utilization of coal plants could significantly add to utility carbon dioxide (CO_2) emissions, which would conflict with the Clinton Administration's commitment to stabilize greenhouse gas emissions at 1990 levels by the year 2000. It states that the Competition-Favors-Coal Scenario projects that annual utility CO_2 emissions will increase by 285 million tons by 2000 and by 737 million tons by 2010; and that the FEIS attributes about 10 percent of the increase to the Rule. It argues that this increase will threaten international commitments of the U.S. Government. The Joint Commenters assert that utility CO_2 emissions are not currently on track to fulfill national and international climate protection objectives and open access competition, to the extent it favors existing coal plants, will exacerbate these trends.

The Joint Commenters then claim that in addition to the emissions impacts that are identified in the FEIS, EPA's technical analysis indicates that the Rule has the potential to cause much larger impacts than the FEIS estimates for the Competition-Favors-Coal Scenario. EPA's evaluation, which Joint Commenters claim does not incorporate worst case scenario assumptions, indicates that the potential increases in NO_X emissions from open access could be more than twice the increases projected in the FEIS Competition-Favors-Coal Scenario in years 2000, 2005 and 2010. The potential that FERC's highest polluting case understates emissions increases to this extent illustrates the uncertainty surrounding the impacts of open access, particularly the uncertainties surrounding the accuracy of the Commission's estimates, and the critical importance of developing mitigation programs.

Authority to Mitigate. The Joint Commenters assert that the Commission's rejection of authority to mitigate environmental impacts is contrary to law and arbitrary and capricious. It states that the Commission's rejection is inconsistent with Commission claims about its sections 205 and 206 authority, and that both NEPA and the FPA permit FERC to mitigate adverse environmental impacts. Thus, while it may be reasonable for the Commission to reject specific mitigation measures, the Commission's decision that it lacks authority to implement mitigation constitutes an arbitrary and capricious exercise of agency authority.

The Joint Commenters argue that NEPA authorizes agencies to consider and address environmental impacts so long as any actions undertaken do not conflict with the agency's authorizing statute. It states that a number of cases support the proposition that FERC's FPA authority is broadened by NEPA—that NEPA policies and goals inform and expand the FPA's definition of public interest. In effect, NEPA establishes a legal nexus between the Commission's primary regulatory duties and environmental protection. Thus, courts have upheld agency mitigation actions under NEPA even when the agencies have no explicit environmental protection mandate. The Joint Commenters assert that the Commission did not address these cases in concluding that it lacks authority to mitigate adverse environmental impacts under sections 205 and 206 and the FPA's general public interest standard.

The Joint Commenters assert that if NEPA is to be given practical effect, agencies must have authority to do more than study the potential environmental impacts of proposed actions. To interpret and administer federal laws in accordance with NEPA policies, agencies must have the authority to use their statutory powers in ways that implement NEPA policies. The arena of permissible environmental action is constrained only by the limits of the agency's jurisdictional authority under its enabling statutes. Thus, the only limits on FERC's ability to implement environmental mitigation are those defined by the FPA. Therefore, the question is whether mitigation falls within the regulatory powers of FERC.

The Joint Commenters argue that the FPA authorizes the Commission to mitigate the environmental effects of its actions, stating that the public interest standard of FPA section 201 encompasses the environmental and other competitive concerns discussed in its request for rehearing. The Joint Commenters state that *NAACP* v. *FPC,* 425 U.S. 662 (1976) and similar cases establish that FERC has jurisdiction to address environmental concerns since such concerns are directly related to FERC's regulation of economic interests in the electric industry.

The Joint Commenters assert that FERC's duty to ensure just and

[845] This aspect of the Joint Commenters' argument is addressed below.

reasonable rates that are not unduly discriminatory or preferential also encompasses non-economic factors in appropriate circumstances. It argues that the Commission's reliance on *Office of Consumers' Counsel* v. *FERC,* 655 F.2d 1132 (D.C. Cir. 1980), to support its narrow reading of the FPA's public interest standard is misplaced.

The Joint Commenters then take issue with the position that the Commission lacks authority to implement mitigation because it has insufficient expertise in air pollution control and because Congress gave EPA authority to address such issues. It states that the record does not support a conclusion that FERC lacks the expertise necessary to provide for mitigation of the Rule's impacts. Moreover, nothing would prevent the Commission from acting in concert with EPA to take advantage of EPA's expertise.

The Joint Commenters state that, unlike the situation in *Office of Consumers' Counsel,* Congress has given FERC, along with EPA and other federal agencies, the responsibility to address the environmental effects of its actions. In this case, Joint Commenters are asking the Commission to mitigate the environmental impacts of its Rule, not to assert jurisdiction proactively over air pollution matters or to usurp EPA's role. Under Order No. 888's logic, no federal agency would have authority to mitigate the environmental impacts of its proposed actions because EPA is the primary agency with environmental expertise and responsibility.

The Joint Commenters then argue that the Commission's jurisdiction to consider environmental issues also derives from a traditional analysis of FERC's jurisdiction over wholesale power rates. It states that if the Commission does not allocate environmental responsibility to high-emission utilities, environmental compliance costs will be transferred to downwind utilities and their customers. These utilities will be required to incur costs to reduce emissions and must increase rates to recapture these costs. Thus, Order No. 888 will directly affect the costs that are included in electric rates, which the Commission has authority to review under sections 205 and 206.

The Joint Commenters conclude their discussion by noting that, while it may have been reasonable for the Commission to reject specific mitigation proposals, the Commission should reexamine the position that it has no authority in this area and instead acknowledge that the exercise of that authority is not warranted here given the conclusions in the FEIS. The Joint Commenters go on to note that EPA proposed in its referral to CEQ a mitigation approach that seeks the Commission's commitment to future actions and outlines immediate actions EPA will take to address the potential NO_X emission increases identified in the FEIS. The Joint Commenters state that although it believes EPA's proposal is reasonable and strongly support the tracking system recommended, the Commission should develop a backup NO_X mitigation mechanism by the end of 1996 to assure that Order No. 888 will be implemented without adverse environmental impacts.

Commission Conclusion

Need for Mitigation. The FEIS examines fully claims that the Rule will have significant environmental impacts requiring mitigation. As stated in Order No. 888:

First, the findings show that, without the rule, NO_X emissions are expected to decline until at least the year 2000. Thereafter, again without the rule, NO_X emissions are expected to increase steadily through the year 2010 (the end of the FEIS study period). The extent of the decrease and the increase will be largely determined by the relative prices of natural gas and coal, the two main fuels used to generate electric power in most regions.

In reaching this conclusion, the FEIS used two ''base'' cases. In one (the ''High-Price-Differential Base Case''), natural gas was assumed to become substantially more expensive compared with coal than it is today. In the other (the ''Constant-Price-Differential Base Case''), natural gas was assumed to maintain essentially the same price relative to coal that has existed for the last ten years. The two cases describe the range of emissions due to fuel price uncertainty without the rule and demonstrate the overall trends of decreases until 2000 and increases thereafter.

Second, the FEIS finds that the rule will not in any significant respect affect these overall trends.

The potential impact of the rule was studied initially under two scenarios. In one (the ''Competition-Favors-Gas Scenario''), the rule is assumed to result in efficiency gains in the electric industry that would tend to favor natural gas as a fuel. In this scenario the effect of the rule is slightly beneficial. Total NO_X emissions are reduced overall by about two percent nationwide from the base cases. In the other (the ''Competition-Favors-Coal Scenario''), the rule is assumed to result in efficiency gains in the electric industry that would tend to favor coal as a fuel. In this scenario the effect is again slight, showing approximately a one percent increase in NO_X emissions nationwide from the base cases. In both scenarios, however, the rule does not have an overall effect on NO_X emission trends.

Stated differently, under any case studied, with or without the rule, there will be an overall net decrease in NO_X emissions through the year 2000. Thereafter, NOx emissions begin to increase. The rule does not materially affect either the decline prior to 2000 or the increase thereafter.

Based on these findings the Commission concludes that a comprehensive, Commission-imposed mitigation scheme to address the environmental consequences of the rule is not appropriate. If competition favors gas, the effects are beneficial and mitigation is unnecessary. If competitive conditions favor coal through the year 2010, and NO_X emissions increase slightly as a result of the rule, these minor effects would be effectively mitigated as a part of a comprehensive NO_X cap and trading allowance scheme developed by EPA in cooperation with the Ozone Transport Assessment Group (OTAG) and administered by EPA and state environmental regulators under the clearly established authority of the Clean Air Act. [846]

The Commission went on to note that it believes the appropriate no-action alternative was used to conduct this analysis. ''An alternative that requires the Commission to reverse all its other open access policies is simply not a 'no-action' alternative. To the contrary, it would require decisive action running counter to the direction from the Congress in the Energy Policy Act and the needs of the marketplace and electricity consumers.'' [847] The Commission then explained:

However, to ensure that the effects of the rule were analyzed fully, the FEIS did study a reference case based on the ''frozen efficiency'' case proffered by EPA and the Department of Energy (DOE). Although, as described below, we believe this case to be highly unlikely, the results show that, even under this scenario, the impacts of the rule are not great and do not vary significantly from those projected by staff under the other assumptions.

In one case requested by EPA, staff studied a combination of assumptions most likely to show significant increases in emissions associated with the rule; the case included EPA's frozen efficiency scenario, coupled with the ''Competition-Favors-Coal'' assumptions. Other cases requested by EPA posit dramatic increases in transmission capacity (that we find highly unlikely). Even this combination of assumptions—geared to demonstrate the greatest impact the rule might have on increased NO_X emissions—produced little in the way of environmental consequences associated with the rule. Under these extreme (and unlikely) conditions, there would still be a net decrease in NO_X emissions until at least the year 2000, albeit a smaller decrease than in the base cases. Comparing projections of emissions for the same years, emissions would be higher than the base cases only by two percent in 2000 and three percent in 2005. It is only in the year 2010, assuming these improbable scenarios, that NO_X emissions associated with the rule would be higher than the base case by even five percent.

[846] FERC Stats. & Regs. at 31,862–63; *mimeo* at 663–65 (footnotes omitted).

[847] *Id.* at 31,863; *mimeo* at 665.

Based on these studies, including the EPA reference case, the Commission endorses the staff findings that the rule will affect air quality slightly, if at all, and that the environmental impacts are as likely to be beneficial as negative. This is true even under scenarios contrived to maximize emissions associated with the rule under circumstances that this Commission believes to be highly unlikely.

Importantly, this is also true in the near- to mid-term. Until the year 2010, even the worst case (the frozen efficiency case) produces results very similar to those produced using assumptions the Commission believes to be reasonable. In short, the rule will not produce an ''ozone cloud'' coming across the Appalachians to threaten the Northeast on the day the rule goes into effect. Assuming that any environmental impacts occur, they are years in the future and may well be beneficial. As a result, calls for Commission mitigation, and in particular for interim mitigation to ''fill the gap'' until programs under the Clean Air Act can be adopted, are unnecessary and disproportionate to the possible effects of the rule. [[848]]

Thus, there is no basis for claims that the Rule will result in large increases in pollution from generating plants operating under less stringent environmental controls. This negates arguments calling for the imposition of mitigation measures to ensure that all entities compete under an identical regulatory regime.

We note in this regard that the Joint Commenters' claim that the Rule may result in emissions increases as large as 315,000 tons per year by the year 2010, and cumulative NO_X increases across the United States of 530,000 tons by 2000 and 2.7 million tons by 2010, is incorrect. The Joint Commenters derive this result by selectively choosing numbers from the FEIS, comparing sensitivity cases designed to be unrealistically low and high extremes. The low emissions case selected is the frozen efficiency case that represents a complete reversal of current industry and regulatory trends that are occurring without the Rule. The high emissions case represents an increase in transmission capacity that cannot reasonably be ascribed to the Rule. The FEIS indicates that these cases were used to examine the sensitivity of findings to certain extreme assumptions maintained by commenters and are not the appropriate cases to use for considering potential environmental impacts from the Rule.

Moreover, the Joint Commenters reference increases from the Rule without noting equally likely decreases. Even with the lower emissions resulting from the unrealistic frozen efficiency case, the FEIS finds decreases in emissions from the Rule when competitive forces lead to greater efficiency for natural gas generation compared to coal.

Actions to Mitigate NO_X Emissions. Moreover, EPA and the Commission have committed to undertake the actions sought by those seeking rehearing on this issue. EPA in its referral to the CEQ concurred with the Commission ''that the open access rule is unlikely to have any significant adverse environmental impact in the immediate future, and that in light of its anticipated economic benefits, implementation of the Rule should go forward without delay.'' EPA also ''concludes that the FERC has conducted an adequate analysis under the National Environmental Policy Act of the environmental impacts of the open access rule under a range of possible scenarios.'' In particular, EPA concurs that the ''FERC made a reasonable choice of models (CEUM) and made assumptions for various factors input into the model that lie within the range of reasonable assumptions.''

EPA also concurred with the Commission that NO_X emissions increases associated with the Rule, if any, should be addressed as part of a comprehensive NO_X emissions control program developed by EPA and the states under mechanisms available under the Clean Air Act. This includes support for the efforts of OTAG to develop standards for measuring the scope of the ozone transport problem and developing emissions reduction strategies.

More significantly, EPA committed to use its authority under the Clean Air Act to support successful completion of the OTAG process. EPA will establish a NO_X cap-and-trade program for the OTAG region through Federal Implementation Plans ''if some States are unable or unwilling to act in a timely manner.'' [849]

EPA also states that if ''the OTAG and Clean Air Act processes fail to produce the necessary pollution limitations in a timely manner, EPA will call upon all other interested Federal agencies to assist in solving the problem.'' In this context EPA would ask the Commission to contribute by further examining, through a Notice of Inquiry, possible strategies for mitigating NO_X emissions increases associated with the Rule. EPA also suggested that if it determines that the problem must be addressed through EPA initiation of Federal Implementation Plans, FERC could then initiate a rulemaking to propose ''suitable means under the Federal Power Act'' for mitigating impacts attributable to the Rule.

The Commission, on May 29, 1996, issued an order responding to EPA's referral. The Commission stated that:

> Given EPA's commitment to address air pollution issues, it is appropriate for EPA to seek assurances that if its best efforts are not successful, other agencies will examine their abilities to address the problem within the scope of their respective statutory authorities. Given the broad powers vested in EPA by the Clean Air Act, we fully expect EPA to succeed. We also note that if EPA is unable ultimately to address the issue, either through the voluntary OTAG process or by means of its authority under the Clean Air Act, we doubt that other agencies will be able to resolve the NO_X emissions problem under more limited authority. In such circumstances, action by the Congress may be necessary.
>
> Nevertheless, we believe that the Commission should be willing, if called upon under the circumstances EPA describes, to consider whether, under the Federal Power Act, it can and should attempt to address NO_X emissions issues attributable to the Rule. Therefore, if EPA concludes that the OTAG process has not succeeded in meeting its objectives in a timely manner, we will initiate a Notice of Inquiry to further examine what mitigation might be permissible and appropriate under the Federal Power Act. Such an inquiry would solicit public comment on how to assess appropriately the air pollution impacts attributable to the Final Rule, suitable ways in which to address such impacts, if any, and the scope of the Commission's authority to address such impacts.

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[848] *Id.* at 31,863–64; *mimeo* at 665–67 (footnotes omitted).

[849] The FEIS at page 7–8 discusses EPA's authority under the Clean Air Act to remedy the interstate transport of air pollution. Section 176A provides that whenever EPA has reason to believe that the interstate transport of air pollutants from one or more states contributes significantly to a violation of national ambient air quality standards in one or more other states, it may establish a transport region for such pollutant. The transport commission is charged statutorily with assessing the degree of interstate transport of the pollutant or precursors to the pollutant throughout the transport region, assessing strategies for mitigating the interstate pollution, and recommending to the EPA Administrator measures to ensure that the relevant State Implementation Plans (which every state is required to have in place to address air pollution) meet the requirements of the Clean Air Act.

A transport commission may request the Administrator to issue a finding under section 110(k)(5) that the SIP for one or more of the states in the transport region is substantially inadequate to meet the requirements of section 110. The Administrator must approve or disapprove such a request within 18 months of its receipt.

Upon approval of recommendations submitted by the transport commission, the Administrator must issue to each state in the OTR to which a requirement of the approved plan applies, a finding under section 110(k)(5) that the implementation plan for such state is inadequate to meet the requirements of section 110. Such finding shall require each such state to revise its SIP to include the approved additional control measures within one year after the finding is issued.

Additionally, under the extraordinary circumstances in which EPA would undertake a Federal Implementation Plan, the Commission would agree to initiate contemporaneously a rulemaking to propose possible mitigation that could be undertaken by the Commission under the Federal Power Act. Such a rulemaking would be undertaken on the basis of the NOI mentioned above and would be appropriate only if environmental harm attributable to the rule that warranted mitigation is demonstrated. The Commission would rely upon information gleaned in the NOI in proposing possible mitigation strategies that are workable, tailored to address consequences attributable to the Rule, and consistent with our statutory authority. In no event would the Commission propose a mitigation strategy that would undermine the purposes of the rule to provide open transmission access on a non-discriminatory basis. We emphasize that neither the NOI nor the rulemaking, if they occur, will affect the implementation of the rule as required under Orders of the Commission. [850]

Thus, EPA has concluded that the Commission conducted an adequate analysis of the impacts of the Rule and agrees that the Rule is unlikely to have any significant adverse environmental impact in the near future. EPA also concurs that NO_X emissions increases associated with the Rule, if any, should be addressed as part of a comprehensive NO_X emissions control program developed by EPA and the states under mechanisms available under the Clean Air Act. This includes support for the efforts of OTAG to develop emissions reductions strategies. EPA will use its Clean Air Act authority to support completion of the OTAG process. EPA is prepared to establish a NO_X cap-and-trade program for the OTAG region through Federal Implementation Plans if states are unable or unwilling to act in a timely manner.

This commitment by EPA puts to rest the concerns expressed by those seeking rehearing on the issues of mitigation and disparate emissions standards. As stated in the FEIS:

The Ozone Transport Assessment Group (OTAG) represents [a] broad[] effort to deal with the interstate transport of pollutants that form ozone. OTAG is a voluntary organization that consists of 37 eastern states, the District of Columbia, and the EPA; industry and environmental groups also participate in the OTAG process. It was organized by the Environmental Council of States to study the transport of ozone and its precursors in the eastern U.S. and to develop mitigation strategies. OTAG is performing extensive photochemical grid modeling to determine ozone transport patterns and to evaluate the efficiency of various control strategies. OTAG intends to submit its findings regarding transport patterns and its recommendations for mitigation of ozone transport to EPA by January 1997.

OTAG is considering a number of strategies to mitigate the problem of ozone nonattainment. One strategy is the imposition of a cap and trading system for NO_X emissions in a 37-state area compromising the Northeast OTR and upwind states. If the cap and trading system becomes effective, it will fully mitigate any NO_X emissions increases attributable to open access transmission within the 37-state area, because increases within this area would have to be offset by a corresponding emission reduction.

The OTAG cap and trade program may not deal directly with emissions of pollutants other than NO_X. However, a cap on NO_X is likely to mitigate CO_2 and mercury increases, because internalizing costs of NO_X controls on coal-fired units is likely to dampen increases in capacity utilization of such units.[851]

The OTAG process includes the players of concern here—both the states from which alleged pollution increases would originate and the states that would be affected by the increased pollution. OTAG has a process underway to determine transport patterns and to evaluate control strategies. One strategy that is being considered is the imposition of a cap and trade system for NO_X emissions like that sought on rehearing here.[852] OTAG originally intended to submit its findings regarding transport patterns and recommendations for mitigation to EPA by January 1997. As a result of its decision to conduct additional modeling to determine the appropriate geographic applicability of emission reduction strategies, OTAG has extended its January timeframe by a few months, and now intends to complete its process by April or May 1997.

While OTAG is continuing its efforts, EPA is moving rapidly forward to remedy in a comprehensive fashion the interstate transport of air pollution. On January 10, 1997, EPA issued a notice of intent to use the authority granted it by sections 110(k)(5) and 110(a)(2)(D) of the Clean Air Act to require states to submit state implementation plan (SIP) measures to ensure that emission reductions are achieved as needed to prevent significant transport of ozone pollution across state boundaries in the Eastern United States. This notice ‘‘announces EPA's intention to conduct the formal process for implementing the regional reductions in ozone precursors that are necessary for areas in the Eastern United States to reach attainment.’’ [853] EPA states that it intends to publish a Notice of Proposed Rulemaking in March 1997 that ‘‘will propose overall amounts or ranges of NO_X and/or VOC emission reductions that each State would need to achieve to reduce the boundary condition concentrations of ozone and its precursors within a specified timeframe and require the submission of SIP controls to achieve these reductions.’’ [854] The notice of inquiry also states that the SIP revision must contain a schedule for adoption and implementation of these measures. It notes that while EPA could allow up to 18 months for SIP submittals under section 110(k)(5), ‘‘EPA is considering a more accelerated schedule for submittals under this SIP call to attain air quality benefits sooner and to facilitate area specific SIP planning.’’ [855] EPA notes that as it goes through the process of developing an implementation program for the new standard, it will be able to take advantage of the information gathered by OTAG and account for emission reductions that result from the recommended strategy. EPA intends to publish the final SIP call notice in summer 1997.

Thus, actions to address the concerns with regard to mitigation and emissions standards disparity are taking place at this time and should be in place in the near future. This lays to rest as well concerns that any near-term impacts of the Rule have not been taken into account.

The Commission's Authority to Mitigate. The PA Com makes an unsupported assertion that the FPA's public interest standard authorizes the Commission to take mitigation measures related to its regulatory actions, and that the Commission should use the results of the OTAG process to develop a mitigation strategy.

The Joint Commenters argue that the Commission has broad authority under NEPA to mitigate the environmental consequences of its proposed actions. It contends that NEPA broadens the Commission's FPA authority—that NEPA policies and goals inform and expand the FPA's definition of the public interest. It also argues that the Commission's duty to ensure just and reasonable rates that are not unduly discriminatory or preferential also

[850] Order Responding to Referral to Council on Environmental Quality, 75 FERC ¶ 61,208 at 61,691–92 (1996).

[851] FEIS at 7–10 through 7–11.

[852] We note in this regard that in a recently completed rulemaking promulgating standards for the second phase of the Nitrogen Oxides Reduction Program under Title IV of the Clean Air Act, EPA authorized states to adopt a NO_X cap and trading program under certain circumstances. ‘‘Acid Rain Program; Nitrogen Oxides Emission Reduction Program’’, 61 FR 67112, 67163 (1996).

[853] 62 FR 1420 (1997).

[854] *Id.* at 1423.

[855] *Id.*

encompasses non-economic factors in appropriate circumstances.

The Joint Commenters conclude that, while it may be reasonable for the Commission to reject specific proposed mitigation measures, the Commission should, at a minimum, acknowledge that the FEIS demonstrates that the exercise of that authority is not warranted in this case. The Joint Commenters add that the Commission should initiate a rulemaking proceeding that considers mitigation options and evaluates the effectiveness of alternative strategies and proposals. The Joint Commenters concur that EPA's commitment to address air pollution issues is reasonable, but would have the Commission develop a backup NO_X mitigation mechanism by the end of 1996.

Thus, the PA Com and the Joint Commenters would have the Commission revisit in this order, by means of a generalized reexamination of the Commission's authority to impose mitigation, the conclusion in Order No. 888 that the mitigation measures recommended by commenters are beyond our authority to implement.

Order No. 888 and the FEIS fully examine the need for mitigation and the Commission's legal authority to impose mitigation measures. That examination led to the conclusion that: (1) the insistence of certain commenters that the Commission adopt and implement mitigation measures is based on significantly overstated assumptions regarding the contribution of the Rule to existing environmental problems, and that these assumptions about the impact of the Rule are wrong; (2) the existence for many years of a significant ozone nonattainment problem in part of the U.S. has led to the development of mechanisms to address this issue; (3) the mitigation recommendations suggested by commenters suffer from serious legal and practical shortcomings; and (4) the mitigation measures recommended by commenters are beyond the Commission's authority to implement and strong policy considerations militate against their adoption.

The PA Com and Joint Commenters have not raised any arguments that warrant revisiting the Commission's exhaustive examination of this issue in Order No. 888 and the FEIS, and we hereby reaffirm those decisions. We note in this regard that the PA Com did not advance a specific mitigation proposal in comments on the EIS and does not challenge the Commission's rejection in Order No. 888 of specific mitigation proposals advanced by other commenters. The Joint Commenters did propose a specific mitigation strategy which the Commission rejected because, among other things, it would have the Commission impose a revenue collection measure. The Joint Commenters do not challenge the Commission's analysis of its proposal or seek rehearing of its rejection. Instead, the Joint Commenters seek an acknowledgement from the Commission that, given the conclusions in the FEIS, the exercise of authority to mitigate is not warranted in this case. As we stated in Order No. 888 and the FEIS, mitigation is not warranted given the conclusions reached in the FEIS. The Commission also notes that we have thoroughly examined our legal authority in Order No. 888 and we find nothing in the arguments on rehearing that persuade us now to a different result. We have agreed to further examine our authority to engage in environmental mitigation through a Notice of Inquiry if EPA determines that the OTAG efforts are not successful. Therefore, it is unnecessary in this context to opine further in the abstract as to the scope of the Commission's mitigation authority.

Because the PA Com and the Joint Commenters have raised no new arguments that were not thoroughly addressed in Order No. 888 and the FEIS, it is unnecessary to repeat here the thorough analysis of this issue set forth in those documents. The Commission declines to grant rehearing on this issue.

Other Mitigation-Related Issues. VT DPS states that the Commission has given inadequate consideration to the possibility that the Rule may unnecessarily exacerbate environmental impacts and that the Commission, therefore, should adopt mitigation.

This statement, which VT DPS fails to substantiate, is incorrect. The FEIS and the process which led to the conclusions contained therein fully consider the environmental impact of the Rule. VT DPS fails to identify any particulars in which the FEIS is deficient. VT DPS's disagreement appears to be a generalized dissatisfaction with the substantive conclusion reached by the FEIS that the Rule will not have significant environmental impacts.

VT DPS next claims that the Commission's environmental review process has not facilitated the ability of affected parties to review all of the modeling assumptions. It also claims that other environmental reviews suggest that the Rule will have more serious NO_X emissions consequences than acknowledged by the Commission.

VT DPS again attacks the FEIS with a broad brush, but fails to identify ways in which the ability of parties to review modeling assumptions has been impeded. Likewise, it does not identify areas in which modeling assumptions have not been identified or any way in which its understanding of the FEIS has been hampered by the alleged unavailability of certain modeling assumptions. VT DPS is very late in raising such claims. The time to raise such issues is during the scoping process or in comments on the DEIS.

It is unclear what other environmental reviews VT DPS is referring to or the ways in which those reviews allegedly suggest that the Rule will have more serious NO_X emissions consequences than acknowledged by the Commission. Even if the unidentified studies reach different results than the FEIS this does not invalidate the conclusions contained in the FEIS. The mere fact of disagreement, even disagreement among experts in a given area, does not invalidate a study. [856]

VT DPS next recommends that the Commission establish an ongoing monitoring program in consultation with environmental agencies. It states that a monitoring program would allow the Commission to take timely action to mitigate any unintended consequences of the Rule.

An EIS is required to be prepared, when appropriate, prior to agency action. As the Supreme Court has stated, the moment at which an agency must have a final statement ready is the time at which it makes a recommendation or report on a proposal for federal action. [857] There is no requirement that an agency continue to evaluate the environmental impacts of a project after it is implemented, particularly where, as here, the agency has determined that the proposal is not likely to have adverse environmental impacts.

Moreover, as discussed extensively above, EPA's commitment to take action with regard to the underlying problems of the interstate transport of air pollutants provides a fuller measure of relief than that sought by VT DPS.

The New York Attorney General claims that it is essential that FERC exercise any authority it may have to mitigate the environmental effects of the Rule because Congress has limited EPA's authority in this regard. The Attorney General also claims that EPA's proposal in its comments of February 20, 1996 on the DEIS to place a cap on NO_X emissions would mitigate the effects of the Rule; it suggests basing

[856] *See, e.g.*, Marsh v. Oregon Natural Resources Council, 490 U.S. 360 (1989); Sierra Club v. Marita, 46 F.3d 606, 623–24 (7th Cir. 1995); Inland Empire Public Lands Council v. Schultz, 992 F.2d 977, 981 (9th Cir. 1993).

[857] Kleppe v. Sierra Club, 427 U.S. 390 (1976).

this system on the MOU. The Attorney General urges implementation of this system on the federal level pursuant to authority residing in EPA and/or FERC.

We note first that Congress has made a full grant of authority to EPA to address the issue of the interstate transport of air pollution. As discussed extensively above, EPA has committed to address this issue, and to use its authority pursuant to the Clean Air Act if states are unwilling to address this issue cooperatively through the MOU process. Thus, EPA has committed to undertake the relief sought by the Attorney General. If EPA is unsuccessful, the Commission has pledged to assist in this effort as discussed above.

D. Emissions Standards Disparity

Order No. 888 addresses claims that the Commission should ''level the playing field'' as to environmental standards. The argument was that unless the Commission imposes mitigation, competitors with ''dirty'' generation will be favored over ''clean'' competitors. Those urging the adoption of measures to level the playing field argue that mitigation of environmental impacts has a direct relationship to ensuring that open access is implemented under terms of economic fairness for all utilities, and not merely those with current low-cost regulatory advantages.

We responded to those arguments in Order No. 888 by noting that:

[A]ll power generation technologies have different costs. For example, hydroelectric facilities which, like coal-fired facilities, may have environmental mitigation conditions imposed on them, may be quite expensive to build compared to gas or oil-fired generation, but their operating costs may be significantly lower. These cost differences may reflect the different costs of complying with mandated environmental requirements; the prudent costs of complying with such mandates may be reflected in rates.

Indeed, sellers come to the power markets with a variety of advantages and disadvantages, many of which are the result of federal laws—for example, tax preferences, labor standards, and similar matters. In empowering the Commission to remedy undue discrimination and promote competition, Congress has not authorized the Commission to equalize the environmental costs of electricity production in order to ensure ''economic fairness.'' Such homogenization of competitors, or their costs, has never been a goal of the FPA.

* * * * *

In short, the ''economic nexus'' urged by commenters advocating that the Commission undertake to regulate air emissions is inconsistent with the ''charge to promote the orderly production of plentiful supplies of electric energy'' envisioned by the FPA.

We have exercised conditioning authority in the past only where necessary to ensure that jurisdictional transactions and rates do not result in anti-competitive effects, or are not unjust, unreasonable or unduly discriminatory or preferential. Thus, the conditions we have imposed have involved economic regulatory matters within our purview under the FPA. Any exercise of conditioning authority must, as the Supreme Court noted in *NAACP*, be directly related to our economic regulation responsibilities; EPA and the other commenters have not demonstrated such a nexus.

This distinction is more evident when one considers the way in which we are authorized to treat the costs of environmental compliance. There are legitimate costs of environmental compliance that should be reflected in jurisdictional rates to the extent prudently incurred, just as the prudent costs of complying with, for example, occupational health and safety requirements designed to protect utility employees should be reflected in jurisdictional rates. This we are authorized to do and we routinely review and allow such costs. However, the fact that the costs of providing utility workers with a safe workplace are properly reflected in utilities' jurisdictional rates does not mean that we have authority to condition sellers' rates or customers' use of jurisdictional services on meeting safety regulations that are in the public interest. The same rationale applies to environmental matters related to the rule. [858]

Rehearing Requests

Pennsylvania PUC. The PA Com asserts that the FEIS does not adequately address challenges posed by the Clean Air Act Amendments of 1990. The PA Com contends that the Rule may shift power production from Pennsylvania plants with strong environmental controls to upwind plants with less stringent controls, and that prevailing climatic patterns may transport the increased pollution downwind. It states that mitigation is needed to prevent degradation of downwind air quality and the imposition of further costs and limits on downwind generation.

[858] FERC Stats. & Reg. at 31,890–91; *mimeo* at 740–43 (footnotes omitted). The FEIS noted in this regard at page J–93 that:

Many factors cause generation sources to have differing costs. Some states impose taxes on generators that others do not. Some fuels are taxed differently than others (e.g., renewable generators such as wind power receive tax incentives that fossil generators do not while fossil fuels receive other tax advantages that renewables do not.) Such differences cannot be said to be unduly discriminatory, especially when they are sanctioned, or even required, by the actions of the Congress or state authorities. If the Commission attempted to ''level'' all of the ''playing fields'' it would be unable to judge any rate to be just and reasonable. Further, traditional rates are not determined through competitive processes but on a cost of service basis. Not all rates have to be determined to be competitive in order to be judged just and reasonable. * * *

The PA Com states that the Clean Air Act Amendments imposed stringent emission standards on Pennsylvania generation, but did not impose similar standards on neighboring states such as Ohio and West Virginia. It claims that the FEIS does not sufficiently consider these requirements. The PA Com concludes that implementing open access without mitigation will place Pennsylvania utilities at a competitive disadvantage, and that this result is inconsistent with the public policy goals of the Clean Air Act and the Federal Power Act. The PA Com also asserts that the Rule may discriminate against Pennsylvania utilities and the Pennsylvania coal industry, and that the combination of the Clean Air Act and Order No. 888 places Pennsylvania at a disadvantage in the competition for new industry and jobs.

The PA Com claims that Order No. 888 may push states in the Northeast Ozone Transport Commission into repudiating the existing MOU. It claims that it is inconsistent for one federal purpose which is statutorily clear (*i.e.*, clean air mandates established by the Clean Air Act Amendments) to be prejudiced by another federal purpose with only inferential statutory authority (*i.e.*, open access under sections 205 and 206 of the FPA).

The PA Com asserts in this regard that Phase II of the MOU will require by 1999 a 55 percent reduction in NO_X emissions in most of Pennsylvania and 65 percent (0.2 lbs/mmBTU) in the Philadelphia area. Title I of the Clean Air Act requires that the Northeast make reasonable progress towards attainment. If the inner zone of states comprising the Ozone Transport Commission do not achieve attainment, Phase III of the MOU will be implemented in 2003. Phase III requires a 75 percent reduction in emissions (0.15 lbs/mmBTU) for the entire state. According to the PA Com, to meet Phase III requirements most Pennsylvania coal-fired stations will have to install Selective Catalytic Reduction technology at a capital cost of $2.3 to $3.5 billion. It states that other Northeast states will be required to make expenditures that are much lower, and that states such as West Virginia and Ohio will not be subject to these requirements at all.

New Jersey BPU. The NJ BPU poses a similar concern. It states that upwind power plants are designed to meet NO_X emission standards which are substantially less restrictive than those required in New Jersey. The NJ BPU claims that this will have a two-fold impact—New Jersey air quality will be degraded through air transport and New Jersey utilities will be placed at a significant cost disadvantage. The NJ BPU states that it is inconsistent to assert substantial incremental benefits associated with competition brought about by the Rule, while asserting that the Rule will not result in any change in the utilization of existing power plants.

NJ BPU asserts that there are disparities in the electric industry among suppliers with regard to environmental impacts and costs, and that the Commission did not take this into account in determining the total economic benefit of a competitive wholesale generation market. It notes that the Commission may consider that it produced an economic benefit if the Rule enables a buyer in the Southeast to displace self-generated 4-cent power with 3-cent power from the Midwest. The NJ BPU contends, however, that if emissions from the plants producing the electricity result in 1.5 cents worth of mitigation costs on a downwind state, an appropriate economic analysis would conclude that the transaction actually increases total costs. NJ BPU asserts that it was inappropriate for the Commission to focus on economic gains while leaving cost issues to be dealt with by other entities.

NJ BPU recommends that the Commission adopt an integrated environmental, economic and energy policy approach which embraces the underlying principles in EPA's acid rain program. It states that the Commission should call for specific, significant and enforceable reductions in NO_X emissions coupled with a market based trading program of emissions. It asserts that this approach would ensure a fair and competitive playing field at a fraction of the expected cost savings from the Rule.

Joint Commenters. The Joint Commenters assert that the Commission has a duty under the FPA to mitigate undue preferences that affect competition in the wholesale power market. It concludes that this mandate must be applied here where implementation of open access policies without concurrent environmental mitigation will cause generation-owning utilities to face a discriminatory competitive situation.

The Joint Commenters note that the Northeast is an ozone nonattainment area because of high levels of ambient ozone pollution, and is therefore subject to strict NO_X reduction requirements. It states that regional utilities have invested significant sums in pollution reduction facilities and cleaner generation to meet legal requirements to reduce emissions. It contends that these utilities will be subject to additional NO_X reduction requirements, thus increasing generation costs, if ambient ozone levels increase as a result of competition.

The Joint Commenters contend that if open access increases emissions, utilities in the Northeast that have increased their generation costs to reduce air pollution will be required to bear additional costs to offset the impacts of increased upwind emissions. It states that the cost to Northeast utilities to offset additional NO_X emissions will likely be substantially higher than the costs would be to upwind competitors to mitigate emissions at the source. It claims that offsetting the impacts of a 250,000 ton NO_X increase in downwind nonattainment areas, where marginal NO_X and volatile organic compound (VOC) control costs average about $3,800 per ton, could total $1 billion. On the other hand, mitigating the pollution increases at generation sources which currently operate with minimal environmental controls would cost about $500 per ton, or $130 million. The Joint Commenters assert that this cost differential will be hidden from the competitive market because Northeast generators will bear the cost.

The Joint Commenters assert that this demonstrates that the wholesale bulk power market in the eastern United States is suffused with an existing undue preference that inordinately favors one category of competitors by allowing them to produce and sell power at a lower marginal cost. This preference exists today as a result of costs incurred in the past to meet Clean Air Act obligations; the FEIS demonstrates that Order No. 888 could worsen this situation as a result of increased sales from older, higher-emitting upwind coal generators.

The Joint Commenters add that, aside from the competitive unfairness of this situation, the undue preferences will produce inefficiencies which distort investment decisions and increase the overall cost to produce electricity—the antithesis of what Order No. 888 is meant to achieve. It asserts that these inefficiencies will occur in four ways:

Sources in downwind nonattainment areas could have to spend hundreds of millions of dollars to address increased air pollution resulting from open access if polluting plants do not mitigate at the source. Thus, less efficient investments will be made to reduce air pollution and the overall cost of generating electricity will be higher than in a competitive market that is not distorted by discrimination.

Order No. 888 could adversely impact the economic dispatch of generating sources under competitive conditions. In the absence of mitigation, generation from higher polluting upwind plants could displace generation from plants in the Northeast that operate more efficiently at the margin. As utilities in the Northeast are required to add more costly emission controls in response to interregional migration of air pollution, their operating costs will be driven up and may exceed the costs of less efficient plants which have avoided such controls. Thus, in the absence of mitigation, Order No. 888 may foster less efficient utilization of generating resources.

Implementation of Order No. 888 without mitigation may distort the market for future generation capacity. If older, more highly-polluting plants can shift the environmental cost of production to other wholesale generators, they are likely to expand their output to address market needs, thus reducing the demand for more efficient, clean-burning generating facilities.

Transmission from the Midwest to the East is often heavily constrained. Consequently, a distorted price signal to increase generation in the Midwest would exacerbate existing constraints and improperly stimulate the construction of new transmission capacity to support additional interregional transactions.

The Joint Commenters conclude that the Commission has an obligation to exercise its authority in non-arbitrary manner, particularly when acting to prevent undue discrimination.

Finally, the Joint Commenters disagree with the Commission's response to this issue in Order No. 888. It asserts that the Commission and the courts have found in the ''price squeeze'' context that the Commission has authority to remedy anti-competitive discrimination, even when it is caused by regulatory practices of others over which it and its regulated public utilities have no control. Second, the Commission has the authority and responsibility to address environmental issues that directly affect and have a nexus to its section 205 and 206 responsibilities. Third, if the competitive market that the Commission wishes to create will not operate fairly or efficiently, the Commission has a duty to consider whether it should go forward at all if it believes it does not have the power to remedy important adverse competitive consequences.

Commission Conclusion

Congress has empowered the Commission to remedy undue discrimination and promote competition; it has not authorized the Commission to equalize the environmental costs of electricity production in order to ensure ''economic fairness.'' Homogenization of competitors, or their costs, has never been a goal of the FPA.

Action in Order No. 888 to remedy undue discrimination in access to the monopoly owned transmission wires that control whether and to whom electricity can be transported in interstate commerce does not require action by the Commission to cure all competitive differences between participants in the utility marketplace. This is particularly true where the disparities arise because Congress has established policies with regard to competing issues of national significance and charged other agencies of the federal government with implementing those policies. The assertion that the Commission must eliminate any competitive disadvantage arising from congressionally mandated policies, including the vital national policies set forth in the Clean Air Act, before it can act to remedy undue discrimination and encourage competition in the electric utility industry is in error.

Furthermore, as noted above, the analysis reflected in the FEIS refutes the claim that the Rule will result in significant environmental impacts. Thus, there is no basis in any event to support requests that the Commission ''level'' the playing field.

Recounted briefly, those findings show that, without the Rule, NO_X emissions are expected to decline until at least the year 2000. Thereafter, again without the Rule, NO_X emissions are expected to increase steadily through the year 2010. The extent of the decrease and increase will be largely determined by the relative prices of natural gas and coal.

The analysis also demonstrates that the Rule will not in any significant respect affect these overall trends. The analysis shows that if the Rule results in efficiency gains in the electric industry that favors the use of natural gas as a fuel, the effect will be slightly beneficial; total NO_X emissions will be reduced overall by about two percent nationwide below what would otherwise be expected to occur. If the Rule results in efficiency gains that favor the use of coal as a fuel, the Rule is expected to increase NO_X emissions approximately one percent above what would otherwise be expected to occur.

Even analyzing the highly unlikely frozen efficiency case, the analysis demonstrates that the impacts of the Rule will not be great and will not vary significantly from those projected by staff under the assumptions discussed above. This study, utilizing a combination of assumptions geared to demonstrate the greatest impact the Rule might have on increased NO_X emissions, produced little in the way of environmental consequences associated with the Rule. Under these extreme (and unlikely) conditions, there would still be a net decrease in NO_X emissions until at least the year 2000, albeit a smaller decrease than in the base cases. Comparing projections of emissions for the same years, emissions would be higher than the base cases only by two percent in 2000 and three percent in 2005. It is only in the year 2010, assuming these improbable scenarios, that NO_X emissions associated with the Rule would be higher than the base case by even five percent.

All told, this analysis demonstrates that the Rule will affect air quality slightly, if at all, and that the environmental impacts are as likely to be beneficial as negative. This is true under scenarios contrived to maximize emissions under circumstances that the Commission believes to be highly unlikely. This is also true in the near to mid-term. Assuming that any environmental impacts occur, they are years in the future and may well be beneficial.

Thus, contrary to the position taken by those seeking to have the Commission impose mitigation, the Rule will not result in impacts requiring mitigation to level the playing field.

Moreover, as also noted above, EPA has committed to address the existing NO_X transport issue, including the contribution of the Rule, if any, to those impacts. It must be emphasized in this regard that the Northeast has experienced significant air pollution problems for many, many years. Much of this pollution is generated by activities within the affected states and within the affected region; the problem is exacerbated somewhat by the airborne transport of pollutants from upwind areas, including pollutants resulting from the generation of electricity that will occur regardless of any future increase in generation that might result from implementation of the Rule.

Put differently, the pollution problems in the individual states and in the Northeast in general result primarily from economic activities within those states. The airborne transport of pollutants, including pollution resulting from existing electric generation, adds to the existing problem to some degree. The analysis in the FEIS demonstrates that open access may increase the amount of upwind generation by some small increment, and thus increase the downwind NO_X levels by an even smaller incremental amount. On the other hand, depending on the future competitive position of natural gas versus coal, a situation over which the Commission has no control, the Rule may decrease the amount of pollution that would otherwise exist and thus decrease downwind pollution. In any event, the Rule will affect existing trends slightly, if at all.

In recognition of the situation described above, which again is likely to be affected only very slightly, if at all, by the Rule, EPA has committed to address the overall issue of NO_X emissions as part of a comprehensive program developed by EPA and the states. EPA has committed to use its authority under the Clean Air Act to successfully complete the OTAG process. EPA states that it will, if necessary, establish a NO_X cap-and-trade program for the OTAG region through Federal Implementation Plans if some states are unable or unwilling to act in a timely manner.

As discussed in the FEIS, and as noted above, OTAG has efforts underway to develop responses to this problem. For example, OTAG intends to submit its findings regarding ozone transport patterns and its recommendations for mitigation of ozone transport to EPA by April or May 1997. If this process is less than fully successful, the Clean Air Act authorizes EPA to act in a relatively short time-frame to address this problem. EPA has committed to exercise this authority to address the problem.

It must be emphasized that EPA has stated its intent to address the problem regardless of the effects of the Rule. Even if the Rule results in environmental impacts, those incremental impacts will be addressed as part of the comprehensive NO_X regulatory developed by EPA in conjunction with the states.

Thus, EPA has committed to undertake the mitigation sought by the PA Com, NJ BPU and Joint Commenters. The Commission has stated its intent to participate in this process as discussed above. This result negates claims that implementing open access without mitigation will place downwind utilities and the Pennsylvania coal industry at a competitive disadvantage. Accordingly, the requests that the Commission impose mitigation measures to ''level'' the environmental playing field are denied.

E. Short-Term Consequences of the Rule

The FEIS projects future electric powerplant emissions under a range of assumptions without the Rule (base cases). These results are then compared to what electric powerplant emissions are likely to be under corresponding assumptions with the Rule in place (Rule scenarios). The study utilizes three reporting years: 2000, 2005, and 2010. These reporting years were chosen because they cover a reasonable time frame for the study. Beyond 2010, the projections are dependent on too many unforeseeable factors to be meaningful.[859]

Although the effects of the Rule will begin to occur when the final Rule is issued, the effects should develop gradually over time. Measurable effects are expected to be clearly observable by the year 2000, though not necessarily fully complete.[860]

The FEIS analysis of the Rule scenarios shows that NO_X emissions are expected to decrease significantly between 1993 and 2000. The Competition-Favors-Gas Scenario demonstrates that the Rule will reinforce decreases already present in the base case. Thus, the Rule will enhance underlying environmental improvements. While the Competition-Favors-Coal Scenario demonstrates small emissions increases, NO_X emissions nonetheless continue to decrease from 1993 to 2000. A similar trend is also seen on a regional basis. The Rule does not alter the basic pattern of environmental improvement.[861]

Rehearing Requests

New Jersey BPU. The NJ BPU claims that the FEIS fails to recognize possible short-term effects the Rule may have on existing ozone problems in the Northeast, and that the failure to address short-term consequences is of particular importance to nonattainment states who must meet Clean Air Act attainment dates in 1996 and 1999.

Joint Commenters. The Joint Commenters claim that by examining the period between 2000 and 2010, the FEIS fails to analyze near-term impacts and the need for a short-term mitigation strategy. Joint Commenters note that the Rule will be implemented almost immediately, and that changes in generation plant utilization that give rise to the greatest environmental concerns may occur very quickly.

The Joint Commenters are concerned that the FEIS does not consider how projected environmental effects prior to 2000 would impact air quality and Clean Air Act attainment deadlines. The Joint Commenters contest the conclusion that utility NO_X emissions will decline between 1993 and 2000. It states that emissions will increase each year between 1993 and 2000 except in 1996 and 2000, when large NO_X reductions will be implemented pursuant to the Clean Air Act. The Joint Commenters also contend that it is irrelevant whether clean air programs will cause overall emissions to be lower in 2000 than they were in 1993; the relevant question is whether emissions will be higher with Order No. 888 than without it.

The Joint Commenters contend that the data presented in the FEIS for the year 2000 suggest that, if the Rule is considered in isolation, there will be potentially significant short-term emissions increases in the period 1996–2000. It states that the FEIS indicates that implementation of the Rule under the Competition-Favors-Coal Scenario with expanded transmission will lead to an additional 132,000 tons of NO_X emissions in 2000 compared with the frozen efficiency reference case. It contends, assuming a linear increase, that this means there could be an additional 75,000, 94,000 and 113,000 tons of NO_X emissions as a result of the Rule in 1997, 1998, and 1999, respectively.

Commission Conclusion

The Joint Commenters' claims that implementation of the Rule will lead to an additional 132,000 tons of NO_X emissions in the year 2000 in incorrect. As is the case with regard to its assertion above that the Rule will result an additional 315,000 tons of NO_X emissions in 2010, this impact was derived by selectively choosing numbers from the FEIS, comparing two sensitivity cases designed to be unrealistically low and high extremes. The low emissions case is the frozen efficiency case that represents a complete reversal of current industry and regulatory trends that are occurring without the Rule. The high emissions case represents an increase in transmission capacity that cannot reasonably be ascribed to the Rule. As stated in the FEIS, these cases were selected to examine the sensitivity of FEIS findings to certain extreme assumptions maintained by commenters and are not the appropriate cases for determining potential environmental impacts from the Rule.

Moreover, we note that the Joint Commenters reference increases from the Rule without noting equally likely decreases. Even with the lower emissions resulting from the unrealistic frozen efficiency case, the FEIS finds decreases in emissions from the Rule when competitive forces lead to greater efficiency for natural gas generation compared to coal.

The Commission has analyzed the Rule and found that its impacts will be insignificant. We also note that even if the Rule were to result in short-term emission increases, EPA has signaled its willingness to address the transport of pollutants in a timely fashion. As discussed above, EPA has concluded that any emissions increases associated with the Rule should be addressed as part of a comprehensive NO_X emissions control program developed by EPA and the states under mechanisms available under the Clean Air Act. This approach includes support for OTAG efforts to develop emissions reduction strategies. OTAG plans to submit its findings and mitigation recommendations to EPA by April or May 1997. As discussed above, EPA has issued a notice of intent to adopt by summer 1997 a rule that would require state implementation plan measures to ensure that emission reductions are achieved as needed to prevent significant transport of ozone pollution across state boundaries in the Eastern United States. EPA is contemplating establishing deadlines for state implementation plan submittals ranging from six months to 18 months following the date of publication of its notice of final rulemaking.

The instant Rule will affect the existing NO_X transport issue very little, if at all. As stated in Order No. 888, the Rule is not the appropriate vehicle for resolving this debate. The appropriate regulatory mechanism for addressing the overall NO_X problem, including emissions from electric utility generating plants, is a NO_X emissions cap and allowance trading scheme along the lines of that developed by the Congress under the Clean Air Act for SO_2 emissions. As noted, EPA has committed to implement this approach. Even if there are slight environmental impacts associated with the Rule, they are better and more effectively addressed as part of a comprehensive NO_X regulatory program.

G. Cost Benefit Analysis

''The legal and policy cornerstone'' of Order No. 888 ''is to remedy undue discrimination in access to the monopoly owned transmission wires that control whether and to whom electricity can be transported in interstate commerce.'' [862] As reiterated in the FEIS, the purpose of the Rule is to increase access to non-discriminatory transmission services and thereby increase competition in wholesale electric markets.[863]

The FEIS states that the Rule will give wholesale power customers a greater opportunity to obtain competitively priced electricity. Competition will create benefits through better use of existing assets and institutions, new market mechanisms, technical innovation, and less rate distortion.

[859] FEIS at ES–9, 3–1.

[860] *Id.* at 3–1.

[861] *Id.* at 5–15.

[862] FERC Stats. & Regs. at 31,634; *mimeo* at 1.

[863] FEIS at ES–13 through ES–16.

Only the first—better use of existing assets and institutions—was estimated quantitatively: approximately $3.8 to $5.4 billion per year. The FEIS also discusses other benefits that cannot be quantified but may be large. Based on the experience of, for example, the natural gas and telecommunications industries, the Commission opined that the other three are likely to increase industry efficiency—and benefits—substantially.[864]

As described elsewhere in this order, the FEIS also discusses extensively possible environmental effects (*i.e.*, costs) of the Rule. It concludes that the Rule could raise or lower national emissions slightly, but will not have a significant effect on the environment.

Rehearing Requests

The Joint Commenters contend that the analysis of projected benefits from the Rule appears to be inadequately substantiated and uses assumptions that are inconsistent with those used to reach a finding of no significant impact on environmental issues. Although Joint Commenters do not challenge the conclusion that Order No. 888 will result in economic benefits, it states that the benefits identified in the FEIS are inadequately substantiated and do not reflect a balanced analysis. It claims that courts have held that when economic development is the selling point or raison d'etre of an action NEPA requires the agency to provide a specific comparison of economic benefits versus environmental costs. It concludes that the analysis of the economic benefits of Order No. 888 is tipped in favor of benefits, especially when contrasted with the analysis of projected environmental impacts.

Joint Commenters state that the conclusion that benefits will range from $3.76 to $5.37 billion per year is not properly documented and cannot be relied upon as justification for implementing the Rule without mitigation. It contends that the Commission is counting benefits from changes that are unrelated to the Rule, such as benefits resulting from higher plant availability factors. Joint Commenters claim that this assertion appears to be inconsistent with industry reactions to competition to date. The same is true of planning reserve margins. It states that key assumptions used to define the operating savings, particularly fuel price assumptions, are unreasonable. It adds that these savings are the ones that give rise to adverse environmental effects due to increased utilization of existing low-cost coal generation. Therefore, it is inappropriate to count these economic benefits without examining the offsetting environmental costs, which increase as the level of the asserted benefits increase.

Finally, Joint Commenters assert that the FEIS does not address potential costs associated with implementing the Rule. These include costs to the Northeast and other regions of additional environmental compliance and the impact on public health of additional pollution; socioeconomic costs associated with utility downsizing; potential adverse effects on nuclear power plant operations from competition; or potential regulatory costs associated with compliance with Order No. 888. Thus, Joint Commenters conclude that the FEIS does not provide a basis for calculating the net benefits of Order No. 888. It also states that the FEIS does not provide a basis for concluding that the potential savings will exceed the additional costs associated with increased use of coal generation without mitigation.

Commission Conclusion

The fulcrum of Joint Commenters' challenge is its claim that when economic development is the selling point of a proposed action, NEPA requires the agency to provide a specific comparison of economic benefits versus environmental costs. The Joint Commenters do not challenge the conclusion that the Rule will result in economic benefits. Rather, it claims that the benefits identified in the FEIS are not adequately substantiated and do not reflect a balanced analysis of benefits versus costs. This argument is made to further the claim, asserted by Joint Commenters in various forms, that the Commission must impose mitigation to ''level'' the playing field.

The Joint Commenters' argument misapprehends the purpose of Order No. 888, the role a cost-benefit analysis plays in an EIS, and the reasons for the Commission's discussion of the economic benefits of the Rule.

The purpose of the Rule is not to foster economic development, although the Commission anticipates that this will be a salutary effect of open access. The purpose of the Rule is to promote competition in the wholesale bulk power markets by remedying undue discrimination in access. The fact that the Rule will create benefits through better use of existing assets and institutions, new market mechanisms, technical innovation, and less rate distortion is a consequence rather than the purpose of the Rule.

The Joint Commenters also mistake the role a cost-benefit analysis plays in an EIS. The CEQ regulations implementing NEPA set forth the requirements pertaining to a cost-benefit analysis at 40 CFR 1502.23 (1996):

> If a cost-benefit analysis relevant to the choice among environmentally different alternatives is being considered for the proposed action, it shall be incorporated by reference or appended to the statement as an aid in evaluating the environmental consequences. To assess the adequacy of compliance with section 102(2)(B) of the Act the statement shall, when a cost-benefit analysis is prepared, discuss the relationship between that analysis and any analyses of unquantified environmental impacts, values, and amenities. For purposes of complying with the Act, the weighing of the merits and drawback of the various alternatives need not be displayed in a monetary cost-benefit analysis and should not be when there are important qualitative considerations. In any event, an environmental impact statement should at least indicate those considerations, including factors not related to environmental quality, which are likely to be relevant and important to a decision.

Thus, the function of a cost-benefit analysis is to assist in the choice among environmentally different alternatives. As discussed above, the Commission's recitation in the FEIS of the anticipated economic benefits of the Rule is not undertaken to assist in the choice among environmental different alternatives. The FEIS discusses the expected economic benefits of the Rule in a broader context, noting that ''[t]he most important socioeconomic effect of the proposed rule is expected to be potentially large benefits to ratepayers and to the economy as a whole.'' [865]

The authorities cited by the Joint Commenters do not alter this conclusion. The Commission is not using the benefits of the Rule as a selling point to go forward with the action while ignoring disadvantages that might flow from it. The FEIS fully examines the impacts of the Rule and concludes that implementation of the Rule will not result in adverse environmental consequences. The Joint Commenters disagreement is with this substantive conclusion, not with the alleged failure to conduct a cost-benefit analysis. Their disagreement does not mean, however, that the Commission has ignored the disadvantages that Joint Commenters assert would flow from the Rule. In brief, as discussed throughout the FEIS, Order No. 888, and this order on rehearing, the Commission has examined the impacts of the Rule and

[864] The discussion of the economic benefits of the Rule in found in the FEIS at ES–13 through ES–16 and 5–64 through 5–75.

[865] FEIS at 5–64.

concluded that it will not result in environmental harms.

Thus, even under the broadest possible interpretation of the cost-benefit analysis requirement, the Commission has evaluated the benefits of the Rule against its impacts and concluded that the benefits are likely to be significant and that the impacts are likely to be insignificant.[866]

The D.C. Circuit rejected the underlying argument advanced here by the Joint Commenters in *Public Utilities Commission of the State of California* v. *FERC*, 900 F.2d 269 (D.C. Cir. 1990). There, California contended that the Commission did not comply with NEPA in granting an Optional Expedited Certificate (OEC) permitting construction of a natural gas pipeline. California argued that the Commission could not have balanced the adverse environmental effects against the need for the project because under the OEC procedures it made no particularized inquiry into the economic benefits of the pipeline. The court responded that:

> Two of our cases speak of a NEPA requirement that ''responsible decisionmakers * * * fully advert[] to the environmental consequences'' of a proposed action and ''decide[] that the public benefits * * * outweigh[] the[] environmental costs.'' *Illinois Commerce Comm'n* v. *ICC*, 848 F.2d 1246, 1259 (D.C.Cir.1988); *Jones* v. *District of Columbia Redevelopment Land Agency*, 499 F.2d 502, 512 (D.C.Cir.1974). Though the Commission engaged in an ''individualized consideration and balancing of environmental factors,'' as required by *Calvert Cliffs' Coord. Comm.* v. *United States Atomic Energy Comm'n*, 449 F.2d 1109, 1115 (D.C.Cir.1971), its evaluation of the nonenvironmental aspects of the pipeline was not individualized. As to them the Commission stated that ''the interests of the public articulated in *our adoption of the optional certificate process* [i.e., Order No. 436] outweigh, on balance, the relatively insubstantial environmental harm which will result from a properly mitigated WyCal Pipeline.'' *Mojave Pipeline Co.,* 46 FERC at 61,168 (emphasis added).
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> California's insistence on a particularized assessment of non-environmental features finds no support in the statutory language. See NEPA § 102, 42 U.S.C. § 4332 (requiring the agency to consider a variety of environmental, not economic, factors). Its theory would disable any number of efforts at streamlining the resolution of regulatory issues that have nothing to do with the environment. An agency's primary duty under the NEPA is to ''take[] a 'hard look' at environmental consequences.'' *Kleppe* v. *Sierra Club*, 427 U.S. 390, 410 n. 21, 96 S.Ct. 2718, 2730 n. 21, 49 L.Ed.2d 576 (1976). We will not extend that statute well beyond its realm so as to create unnecessary conflicts with others. [[867]]

Thus, an agency need not conduct a particularized assessment of the nonenvironmental features of a proposal, in particular its economic benefits or costs. The Commission nonetheless examined the potential costs of the Rule and determined that those costs will be very small and may be positive instead of negative in any event. The Commission has also examined the benefits of the project and concluded that it will have substantial benefits. Accordingly, the request for rehearing is denied.

H. Socioeconomic Impacts

The FEIS examines the socioeconomic impacts of the Rule, including whether the Rule will result in regional shifts in economic activity (especially electric generation and coal mining).[868] The analysis demonstrates that an effect of a more competitive industry may be increased use of existing electric generating facilities. Consequently, it seems likely that those who supply fuel to existing plants could see a higher demand for their output as a result of the Rule. The FEIS notes that this might not be true in all places, however, if factors such as changes in environmental standards work in the opposite direction. The FEIS does not attempt to measure local or site-specific impacts given the speculative nature of such impacts.

The FEIS also notes that open access could lead to changes in employment patterns, but concludes that it is highly uncertain, however, which changes are likely to result from restructuring.[869] The FEIS notes that some changes should lead to cost reductions that will tend to increase jobs in other industries, as well as lower rates for other consumers. Lower power bills can make other industries more competitive and lead them to increase employment.

The FEIS also notes that the Rule is only part of the restructuring currently affecting the industry. Employment in traditional utilities has fallen in recent years. Developments at the state and federal levels will increase competition in the industry even without the Rule. Given the highly uncertain nature of future developments in the electric industry and the complex, dynamic economic issues involved, the FEIS concludes that any quantitative estimate of changes in employment (or even the direction of change) would be highly speculative.

Rehearing Requests

The PA Com claims that socioeconomic impacts that may result from regional economic shifts occurring as a result of the Rule are not adequately discussed in the FEIS. It states that Order No. 888 contemplates a reduction in the amount of coal-fired generation, and that if Pennsylvania generation is shut-down or dispatched less often in favor of generation that is not subject to the same environmental costs and requirements, less Pennsylvania coal will be mined.

The PA Com states that Pennsylvania produces 60 million tons of coal a year, most of which is purchased by Pennsylvania electric utilities. It alleges that the Pennsylvania coal industry provides 9,200 direct mining jobs and 9,500 support service jobs. Coal sales contribute $1.5 billion to the Pennsylvania economy each year and provide an annual payroll of $600 million. The PA Com adds that if coal production declines, the state may curtail efforts to reclaim abandoned mines and coal refuse piles.

The PA Com also contends that social obligations now borne by transmission owning utilities—demand side management programs, integrated resource planning, low-income assistance programs, and federal environmental mandates—have an impact upon price and the market for power, and that utilities might view these obligations as an impediment to competition. It claims that third parties who wish to use the transmission system may balk if they are required to contribute to those social goals.

Finally, the PA Com claims that functional unbundling, open access on a comparability basis, and increased competition may impact reliability of service. It states that it is concerned that reliability is subordinate to economic concerns, and that if reliability is not an articulated foundation of FERC actions, system reliability may suffer. It concludes that the FEIS assumes that reliability will be enhanced by open access, but that this assumption is not adequately explained.

Commission Conclusion

The PA Com's concerns as to the alleged socioeconomic impacts of the Rule are based on a series of tenuous economic ''what-ifs.'' It assumes that the Rule will result in a reduction in Pennsylvania generation. It assumes from this that less coal will be mined in

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[866] In point of fact, the overall thrust of the FEIS is to analyze and discuss the projected costs of the Rule. The discussion of the projected benefits of the Rule comprise a tiny fraction of that discussion. The Joint Commenters dissatisfaction with the results of the analysis does not mean that the projected impacts of the Rule were not discussed in full.

[867] Public Utilities Commission, 900 F.2d at 282 (brackets, ellipses, and emphasis in original).

[868] FEIS at 5–64 and 5–75 through 5–76.

[869] Id. at 5–75 through 5–76.

Pennsylvania and that Pennsylvania will suffer adverse economic consequences. It then assumes that this might lead Pennsylvania to curtail efforts to reclaim abandoned surface and strip mines. No basis has been shown to support the elements in this chain of assumptions. The effects Pennsylvania fears are simply too speculative to assess at this time.

Moreover, the PA Com's concerns stem from the postulated *economic* impacts of the Rule rather than from the alleged impact of the Rule on the *physical environment.* Thus, its concerns are not proper for consideration in an EIS. The CEQ states that socioeconomic impacts alone do not warrant study in an EIS.[870] The CEQ also states that an agency must make reasonable efforts in preparing an EIS to acquire relevant information concerning socioeconomic impacts when economic or social *and* natural or physical environmental effects are interrelated.[871] If such effects are not interrelated, they need not be considered. In this case, the PA Com's concerns stem from what it anticipates will be the economic impact of the Rule on Pennsylvania, and not from the natural or physical environmental impacts of the Rule. Thus, these concerns are not proper for consideration in an EIS.[872]

The approach to such issues is perhaps best symbolized by the Supreme Court's decision in *Metropolitan Edison Co.* v. *People Against Nuclear Energy,* 460 U.S. 766 (1983). In that case, People Against Nuclear Energy (PANE) contended that NEPA required the Nuclear Regulatory Commission to consider whether restarting the Three Mile Island-1 nuclear reactor after the accident at the Three Mile Island-2 reactor would ''cause both severe psychological health damage to persons living in the vicinity, and serious damage to the stability, cohesiveness, and well-being of the neighboring communities.''[873] The court rejected this argument:

> The theme of § 102 is sounded by the adjective ''environmental'': NEPA does not require the agency to assess *every* impact or effect of its proposed action, but only the impact or effect on the environment. If we were to seize the word ''environmental'' out of its context and give it the broadest possible definition, the words ''adverse environmental effects'' might embrace virtually any consequence of a governmental action that someone thought ''adverse.'' But we think the context of the statute shows that Congress was talking about the physical environment—the world around us, so to speak. NEPA was designed to promote human welfare by alerting governmental actors to the effect of their proposed actions on the physical environment.
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> * * * Thus, although NEPA states its goals in sweeping terms of human health and welfare, those goals are *ends* that Congress has chosen to pursue by *means* of protecting the physical environment. [874]

Even though it was not incumbent upon it to do so, the Commission analyzed the concerns raised by the PA Com to the extent it was practicable to do so. The impacts of the Rule on future levels of coal-fired generation in Pennsylvania or on employment in a specific geographic area or in a specific economic sector are influenced by a virtually unlimited roster of other factors, and thus are too speculative to be useful.

I. Coastal Zone Management Act

Order No. 888 found that the Rule does not constitute a federal activity subject to compliance with the Coastal Zone Management Act, 16 U.S.C. § 1451 *et seq.* (CZMA).[875] Order No. 888 concluded that:

> Connecticut has in any event waived its right to request a consistency determination for the Commission's rulemaking. Connecticut's coastal management program's list of federal agency activities likely to require a consistency determination does not (for good reason) describe rulemakings of this kind, and the rule will not ''result in a significant change in air or water quality within the management area'' (the program's catch-all category). In addition, Connecticut did not notify the Commission of its conclusion that the Rule requires a consistency determination until well after 45 days from receipt of several notices of the rulemaking proceeding. Consequently, pursuant to 15 CFR 930.35(b), Connecticut has in any event waived its right to request a consistency determination for this rulemaking. [876]

Rehearing Requests

The Connecticut Department of Environmental Protection (Connecticut DEP) requests that the Commission determine whether Order No. 888 is a federal activity requiring a coastal consistency determination, determine whether the Rule is consistent with Connecticut's coastal management plan (CMP), and consider the impacts that promoting competition and altering transmission and generation patterns may have on water quality in the Long Island Sound. The Connecticut DEP also requests that the Commission mitigate potential increases in nitrogen and sulphur oxide emissions occurring as a result of the Rule.

Commission Conclusion

On August 20, 1996, the Commission responded to the Connecticut DEP, issuing a consistency determination and a negative determination. The response notes that the FEIS focuses on the concerns raised by the Connecticut DEP and concludes that the most important factor determining changes in future emissions is the relative competitive

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[870] The CEQ regulations, 40 CFR 1508.14 (1996), state that ''economic or social effects are not intended by themselves to require preparation of an environmental impact statement.'' *See also* Panhandle Producers & Royalty Owners Association v. Economic Regulatory Administration, 847 F.2d 1168, 1179 (5th Cir. 1988); Olmstead Citizens for a Better Community v. United States, 793 F.2d 201, 205 (8th Cir. 1986).

[871] The CEQ regulations, 40 CFR 1508.14 (1996), provide that ''[w]hen an environmental impact statement is prepared and economic or social and natural or physical environmental effects are interrelated, then the environmental impact statement will discuss all of these effects on the human environment.'' This limitation has been read very strictly. In *Stauber v. Shalala,* 895 F.Supp. 1178, 1194 (W.D.Wis.1995), for example, the court responded to a claim that a proposed action would cause both environmental and socioeconomic harms and that for this reason an EIS was necessary. The court found that:

> This assertion is insufficient to satisfy the ''interrelatedness'' requirement of § 1508.14. I read 40 C.F.R. § 1508.14 to mean that it is only after an agency determines that the socioeconomic impact of the proposed agency action is likely to cause environmental harms itself that the agency needs to discuss the socioeconomic effects in the environmental impact statement. *See Breckinridge v. Rumsfield,* 537 F.2d 864, 866 (6th Cir.1976) (accord), *cert. denied,* 429 U.S. 1061, 97 S.Ct. 785, 50 L.Ed.2d 777 (1977). This reading fully comports with the plain language of the regulation. * * *

[872] It is interesting to note in this regard that Pennsylvania recently adopted electric restructuring legislation of its own establishing retail wheeling. It thus became the fourth state in the Northeast to do so; the others are Massachusetts, Rhode Island, and New Hampshire. The legislation was described by the Governor of Pennsylvania as creating a ''critical competitive advantage'' for Pennsylvania. *The Energy Daily,* December 4, 1996.

[873] Metropolitan Edison Co., 460 U.S. at 769. PANE also asserted that NEPA required consideration of ''[t]he perception, created by the accident, that the communities near Three Mile Island are undesirable locations for business or industry, or for the establishment of law or medical practice, or homes compounds the damage to the viability of the communities.'' *Id.* at 770 n.2.

[874] *Id.* at 772–73 (emphasis in original) (footnote omitted). The continuing validity of the argument that socioeconomic effects are to be considered in an EIS if the federal action has a primary impact on the natural environment is doubtful. The court in *Olmsted Citizens for a Better Community* v. *United States, 793 F.2d 201, 206 (8th Cir. 1986)* stated that:

> [I]t is unlikely that such a distinction survives the recent Supreme Court holding in *Metropolitan Edison.* That decision, as discussed above, was based on congressional intent, and there is no suggestion that Congress contemplated that the process it designed to make agencies aware of the consequences of their actions with regard to the physical environment would be converted into a process for airing general policy objections anytime the physical environment was implicated. Such a rule would divert agency resources away from the primary statutory goal of protecting the physical environment and natural resources. * * *

[875] FERC Stats. & Regs. at 31,895; mimeo at 754.

[876] *Id.* at 31,895–96; *mimeo* at 755–56 (footnote omitted).

position (*e.g.,* price) of coal and natural gas. Depending on the relative prices of these fuels, emissions from electric generating facilities may increase slightly or decrease slightly. Regional effects, including those for the region encompassing Connecticut, are projected to be similar. The response also notes that these estimates fall within the ''noise'' level of the model. That is, they are smaller than the uncertainties in the science underlying the model.

Thus, the response concludes that the Rule will not have an effect on the land and water uses or natural resources of Connecticut. Accordingly, the Commission issued a negative determination pursuant to the regulations implementing the CZMA, 15 CFR 930.35(d). [877]

The response also notes that even if the Rule were to have a minimal effect on Connecticut's coastal zone, the Rule is consistent to the maximum extent practicable with the enforceable policies of the Connecticut Coastal Management Plan (Connecticut Plan). The Connecticut Coastal Management Act and supporting policies which provide the basis for the Connecticut Plan require that activities be consistent with the Clean Air Act. The Connecticut Plan provides that activities are not assumed to directly affect Connecticut, and thus do not require a consistency determination, unless they ''would result in a significant change in air or water quality.''

The August 20, 1996 response concludes that the Rule is consistent with the requirements of the Clean Air Act and will not result in a significant change in air or water quality in Connecticut. In fact, depending on the future prices of fuel, the Rule is equally likely to improve air quality over Connecticut and decrease emissions deposition in the waters of the Long Island Sound. Thus, the Rule is consistent with the Connecticut Plan regardless of any slight effects it may have.

Finally, the response notes that the action sought by Connecticut DEP to ensure consistency with the Connecticut Plan has already been taken in any event. Following issuance of the Rule, EPA, the federal agency charged with implementing the Clean Air Act, stated that it would use its authority to comprehensively address NO_X emissions, including any potential incremental increases in emissions that might result from implementation of the Rule, in the 37-state region that makes up the Ozone Transport Assessment Group. This region includes Connecticut. In an Order issued May 29, 1996, the Commission agreed to examine the issue of mitigation of the impacts, if any, of the Rule in the event that EPA and the OTAG states are unsuccessful in addressing the NO_X problem.

Thus, the FEIS demonstrates that the Rule will not have an effect on any land or water use or natural resource of Connecticut's coastal zone. Moreover, the Rule is consistent with Connecticut's CMP. Finally, EPA and the Commission have taken the action sought by Connecticut DEP to ensure consistency with Connecticut's CMP. These actions fully address Connecticut DEP's coastal zone concerns.

VI. Regulatory Flexibility Act Certification

The Regulatory Flexibility Act (RFA) [878] requires rulemakings to either contain a description and analysis of the effect that the proposed or final rule will have on small entities or to contain a certification that the rule will not have a significant economic impact on a substantial number of small entities. In the Open Access and Stranded Cost Final Rules, the Commission certified that the final rules would not impose a significant economic impact on a substantial number of small entities.[879]

NRECA and SBA question this certification.[880] According to NRECA there are about 1,000 rural electric cooperatives and 2,000 municipal electric systems, most of which meet the RFA definition of small electric entity. NRECA states that the Commission has imposed open access, OASIS and code of conduct requirements on non-public utilities. NRECA maintains that if non-public utilities do not meet these requirements, ''they will not retain access over the long-term to the nation's bulk power transmission grid—access they must have if they wish to stay in business.'' [881]

NRECA also contends that the stranded cost issue will affect small non-public utilities ''any time a non-public utility is required to render reciprocal transmission service, and loses a customer as a result of rendering that service, or a TDU [transmission dependent utility] loses a customer to an open access public utility transmission provider.'' [882] NRECA asserts that both the OASIS Final Rule and the Capacity Reservation Tariff NOPR [883] will substantially burden small non-public utilities.[884] NRECA further maintains that the Commission's waiver provisions will not alleviate the burden on small utilities. It states that filing a waiver request with the Commission is burdensome for small utilities.

SBA states that 30 percent (50 of 166) of public utilities are small under the SBA's definition of a small public electric utility.[885] SBA contends that if, as the Commission has found, 11 percent of public utilities are small, the Final Rules will still affect a significant number of small public utilities.

SBA challenges the Commission's reliance on *Mid-Tex Electric Cooperative, Inc.* v. *FERC*.[886] It contends that the Commission should have analyzed the probable effect of the Final Rules on small businesses by projecting, perhaps on the model of the deregulated

[877] In issuing a negative determination, the Commission noted that it questioned whether the CZMA applies to economic regulatory activities involving interstate electric rates and service. The Commission also noted that Connecticut had waived its right to request a consistency determination or negative determination by failing to notify the Commission of its request within 45 days from receipt of the notice of the federal activity. The Commission concluded that it did not waive those arguments by providing Connecticut with a consistency determination and negative determination.

[878] 5 U.S.C. § 601–612.

[879] Open Access Rule, 61 FR 21540 at 21691 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 at 31,898 (1996).

[880] The SBA filed its Request for Rehearing on June 10, 1996, after the statutory deadline for the filing of such a pleading. Accordingly, we will not accept its pleading as a request for rehearing but will, instead, treat it as a motion for reconsideration.

On November 1, 1996, NRECA filed a supplement to its Requests for Rehearing and Clarifications. We will reject the supplement to the request for rehearing as barred by the 30 day time limit for filing petitions for reconsideration. Neither the Commission nor the courts can waive a failure to comply with the statute. *See* Platte River Whooping Crane Critical Habitat Maintenance Trust v. FERC, 876 F.2d 109, 113 (D.C. Cir. 1989); Tennessee Gas Pipeline Company v. FERC, 871 F. 2d 1099, 1107 (D.C. Cir. 1989); Boston Gas Company v. FERC, 575 F.2d 975 (1st Cir. 1978). *Accord* Commonwealth Electric Company v. Boston Edison Company, 46 FERC ¶ 61,253 at 61,757, *reh'g denied*, 47 FERC ¶ 61,118 (1989). We will accept NRECA's supplemental request for clarifications.

[881] NRECA at 42–43.

[882] NRECA at 44.

[883] Capacity Reservation Open Access Transmission Tariffs, Notice of Proposed Rulemaking, IV FERC Stats. & Regs Proposed Regulations ¶ 32,519 (1996), 61 FR 21847 (May 10, 1996) (*Capacity Reservation*).

[884] We will discuss NRECA's arguments concerning the OASIS Final Rule in our order on rehearing in that proceeding. We reject NRECA's reference to the Capacity Tariff Reservation NOPR as inapposite to this proceeding. We have invited comments on the proposed Capacity Reservation Open Access Transmission Tariffs (*Capacity Reservation*, IV FERC Stats. & Regs. Proposed Regulations at 33,235, 61 FR 21847 at 21853) and will discuss those comments in the appropriate proceeding.

[885] SBA Request for Reconsideration at 5. The SBA defines a small public electric utility as one that disposes of 4 Million MWh per year. 13 CFR 121.201.

[886] 773 F.2d 327 (D.C. Cir. 1985) (*Mid-Tex*).

telecommunications industry, how many small electric utilities, as the SBA defines that term, would enter the deregulated electric utility market.

Commission Conclusion

A. Docket No. RM95–8–000 (Open Access Final Rule)

1. Public Utilities

In the Open Access Final Rule we determined that the Rule applies:

to public utilities that own, control or operate interstate transmission facilities, not to electric utilities per se. The total number of public utilities that, absent waiver, would have to have open access tariffs on file is 166. Of these, only 50 public utilities dispose of 4 million MWh or less per year. Eliminating those utilities that are affiliates of other utilities whose sales exceed 4 million MWh or less per year, or are not independently owned, the total number of public utilities affected by the Open Access Final Rule that qualify under the SBA's definition of small electric utility is 19 or 11 percent of the total number of public utilities that would have to have on file open access tariffs.[887]

We do not agree with the SBA that 11 percent of all of the public utilities that would have to file open access tariffs with us is a significant number. Also, the SBA has overlooked several of the other findings we made as to the possible effect of the Open Access Final Rule on small public utilities. As we noted, of the 19 public utilities that would come within the SBA's definition of small electric utility, five have already filed open access tariffs with the Commission, so that the effect of the Open Access Rule on these utilities should not be significant.[888]

Further, the Commission is specifying the non-rate terms and conditions of the tariffs that public utilities must file, so all public utilities need to do is file a rate, and the small public utilities with open access tariffs already on file with us need not even do that. They may elect to continue service under the Open Access Final Rule's non-rate terms and conditions at their existing rates. In our Final Rule we estimated that the cost for filing a rate would not, on average, exceed one half of one percent of total annual sales for small electric utilities,[889] which is not a significant economic impact.

We disagree with SBA that our reliance on *Mid-Tex* is misplaced. In *Mid-Tex,* the court accepted the Commission's conclusion that virtually all of the public utilities that the Commission regulates do not fall within the RFA's meaning of the term ''small entities.'' *Mid-Tex* involved a rule that applies to *all* public utilities. The Open Access Final Rule applies to only those public utilities that own, control or operate interstate transmission facilities, which are a subset of the group of public utilities for which *Mid-Tex* did not require the preparation of a regulatory flexibility analysis.[890]

SBA attempts to distinguish *Mid-Tex* by postulating that the Commission should have attempted to predict how many new entrants into a deregulated market would be small electric utilities, within the SBA's meaning of that term. *Mid-Tex* held just the opposite, deciding squarely that an agency need only consider the businesses that a regulation directly affects.[891] There is no precedent for SBA's suggestion that the Commission must engage in a hypothetical projection of how many entrants likely to enter a deregulated market may be small electric utilities, and we know of no satisfactory way of making such a projection. Entry into the telecommunications industry, which the SBA offers as a model, involves very different costs, distribution and marketing patterns and entirely different technology. There is no way, from looking at what has happened in the telecommunications industry, that the Commission could project, with any degree of accuracy, how many small electric utilities, if any, will enter the market following the effective date of the Final Open Access Rule.

Finally, SBA overlooks, and NRECA unreasonably discounts, the effect that the Commission's waiver rules have on relieving the burden of the Open Access Final Rule on small entities.[892] The Commission has recently issued a number of orders waiving the requirements of the Open Access Final Rule for a number of small electric utilities.[893] As these cases show, the Commission is carefully evaluating the effect of the Open Access Final Rule on small electric utilities and is granting waivers where appropriate, thus mitigating the economic effect of that rule on small entities. Indeed, as we noted in Order No. 888, 5 small public utilities previously had filed open access tariffs, and we have since, in the cases cited above, granted waivers to approximately 17 small public utilities.[894]

2. Non-Public Utilities

We disagree with NRECA's argument that Order No. 888 imposes burdens upon non-public utilities. As we noted in the Final Rule, we do not have jurisdiction to regulate non-public utilities' rates, terms and conditions of transmission service under sections 205 and 206 of the FPA, and there is no requirement in Order No. 888 that non-public utilities file open access tariffs.[895]

In addition, under the waiver provisions of the Open Access Final Rule, small non-public utilities may seek waiver from the reciprocity provision. As reflected in the cases cited above, the Commission has granted waivers of the reciprocity provision to 10 small non-public electric utilities and issued disclaimers of jurisdiction with respect to 19 small electric utilities, thus mitigating the effect of the Open Access Final Rule on small non-public electric utilities.

B. Docket No. RM94–7–000 (Stranded Cost Final Rule)

1. Public Utilities

No rehearing requests addressed this matter.

2. Non-Public Utilities

In Order No. 888, the Commission indicated that the Stranded Cost Final Rule will not impose a significant economic impact on a substantial number of non-public utility small entities because the stranded cost issue would only arise in a proceeding under sections 211 and 212 of the FPA when, in directing transmission, the Commission addresses the stranded cost issue in determining a just and reasonable rate. NRECA counters that the stranded cost issue will ''arise: any time a non-public utility is required to

[887] FERC Stats. & Regs. at 31,897 (1996)(footnotes omitted); *mimeo* at 758–59.

[888] *Id.* at n.1078.

[889] *Id.* at n.1081.

[890] *Mid-Tex,* 773 F. 2d at 340–43.

[891] *Id.*

[892] The Commission's waiver policy follows the SBA definition of small electric utility. *See* 5 U.S.C. § 601(3) and 601(6) and 15 U.S.C. § 632(a). The RFA defines a small entity as one that is independently owned and not dominant in its field of operation. *See* 15 U.S.C. § 632(a). The SBA defines a small electric utility as one that disposes of 4 million MWh or less of electric energy in a given year. *See* 13 CFR 121.601 (Major Group 49–Electric, Gas and Sanitary Services) (1995).

[893] Northern States Power Company, 76 FERC ¶ 61,250 (1996); Central Electric Cooperative, *et al.*, 77 FERC ¶ 61,076 (1996); Black Creek Hydro, *et al.*, 77 FERC 61,232 (1996); Dakota Electric Association, *et al.*, 78 FERC ¶ 61,117 (1997); Soyland Power Cooperative, Inc., *et al.*, 78 FERC ¶ 61,095 (1997); Niobrara Valley Electric Membership Cooperation, Docket Nos. OA96–146–001 and ER97–1412–000, Letter Order issued February 26, 1997.

[894] These total more that the 19 small public utilities we referenced in Order No. 888 because, since the issuance of that order, several entities have repaid their RUS-financed debt and become public utilities subject to our jurisdiction and several new public utilities have been created as the result of the construction of new facilities.

[895] *See United Distribution Companies* v. *FERC,* 88 F.3d 1105, 1170 (July 16, 1996) (''FERC had no obligation to conduct a small entity impact analysis of effects on entities which it does not regulate.'').

render reciprocal transmission service, and loses a customer as a result of rendering that service, or a TDU loses a customer to an open access public utility transmission provider.'' [896] NRECA submits that the adverse economic impact on small non-public utilities will ''arise'' from the stranding of costs, not from the utilities' participation in proceedings at the Commission, and that the Commission ''cannot in good conscience fail at least to probe the potential adverse economic impact on small non-public utilities of the stranded costs they incur as a direct result of Order No. 888.''

Notwithstanding NRECA's argument that small non-public utilities may experience stranded costs outside of a section 211/212 proceeding, as we explain in Section IV.J.1, *supra,* our jurisdiction over the recovery of stranded costs by non-public utilities, and thus our ability to permit an opportunity for recovery of such costs, is limited by statute. With the exception of our section 210 interconnection and sections 211–212 transmission rate jurisdiction, we do not have jurisdiction over the rates of non-public utilities. Because the stranded cost issue would primarily arise as to non-public utilities over which the Commission has jurisdiction in a proceeding under sections 211 and 212 of the FPA when, in directing transmission, the Commission addresses the stranded cost issue in determining a just and reasonable rate,[897] we concluded that the Stranded Cost Final Rule will not impose a significant economic impact on a substantial number of non-public utility small entities.

Because the Commission does not have rate jurisdiction over non-public utilities other than through sections 210, 211 and 212, the Commission does not have the authority to allow them to recover stranded costs other than through rates set under section 212. However, we clarify that nothing in the Final Rule was intended to preclude non-public utilities from including stranded cost provisions in voluntary reciprocity tariffs or from otherwise recovering stranded costs under applicable law. Thus, a non-public utility that chooses voluntarily to offer an open access tariff for purposes of demonstrating that it meets the reciprocity provision can include a stranded cost provision in its tariff. However, adjudication of any stranded cost claims under that tariff is not subject to the Commission's jurisdiction.[898] If a non-public utility wishes to recover stranded costs pursuant to a tariff or otherwise, it can seek to do so subject to the review of the appropriate regulatory or judicial authority.

[896] NRECA at 44.

[897] Stranded costs could also conceivably arise as a result of an ordered interconnection under section 210. However, the rates for such an interconnection would be established pursuant to section 212 and could therefore also include stranded costs.

VII. Information Collection Statement

Order No. 888 contained an information collection statement for which the Commission obtained approval from the Office of Management and Budget (OMB).[899] Given that this order on rehearing makes only minor revisions to Order No. 888, none of which is substantive, OMB approval for this order will not be necessary. However, the Commission will send a copy of this order to OMB, for informational purposes only.

The information reporting requirements under this order are virtually unchanged from those contained in Order No. 888. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426 [Attention Michael Miller, Information Services Division, (202) 208–1415], and the Office of Management and Budget [Attention: Desk Officer for the Federal Energy Regulatory Commission (202) 395–3087].

VIII. Effective Date

Changes to Order No. 888 made in this order on rehearing will become effective on May 13, 1997.

List of Subjects 18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

By the Commission. Commissioners Hoecker and Massey dissented in part with separate statements attached.

Lois D. Cashell,

Secretary.

In consideration of the foregoing, the Commission amends part 35, chapter I, title 18 of the *Code of Federal Regulations,* as set forth below.

[898] Although the Commission would not determine the rate, including the stranded cost component of the rate, of a non-public utility, we would review a public utility's claim that it is entitled to deny service to a non-public utility because the stranded cost component of the non-public utility's transmission rate is being applied in a way that violates the principle of comparability.

[899] One need not respond to a collection of information unless it displays a valid OMB control number. The OMB control number for this collection of information is 1902–0096.

PART 35—FILING OF RATE SCHEDULES

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. 7101–7352.

2. Part 35 is amended by revising § 35.26 to read as follows:

§ 35.26 Recovery of stranded costs by public utilities and transmitting utilities.

(a) *Purpose.* This section establishes the standards that a public utility or transmitting utility must satisfy in order to recover stranded costs.

(b) *Definitions.*—(1) *Wholesale stranded cost* means any legitimate, prudent and verifiable cost incurred by a public utility or a transmitting utility to provide service to:

(i) A wholesale requirements customer that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility; or

(ii) A retail customer that subsequently becomes, either directly or through another wholesale transmission purchaser, an unbundled wholesale transmission services customer of such public utility or transmitting utility.

(2) *Wholesale requirements customer* means a customer for whom a public utility or transmitting utility provides by contract any portion of its bundled wholesale power requirements.

(3) *Wholesale transmission services* means the transmission of electric energy sold, or to be sold, at wholesale in interstate commerce or ordered pursuant to section 211 of the Federal Power Act (FPA).

(4) *Wholesale requirements contract* means a contract under which a public utility or transmitting utility provides any portion of a customer's bundled wholesale power requirements.

(5) *Retail stranded cost* means any legitimate, prudent and verifiable cost incurred by a public utility to provide service to a retail customer that subsequently becomes, in whole or in part, an unbundled retail transmission services customer of that public utility.

(6) *Retail transmission services* means the transmission of electric energy sold, or to be sold, in interstate commerce directly to a retail customer.

(7) *New wholesale requirements contract* means any *wholesale requirements* contract executed after July 11, 1994, or extended or renegotiated to be effective after July 11, 1994.

(8) *Existing wholesale requirements* contract means any *wholesale*

requirements contract executed on or before July 11, 1994.

(c) *Recovery of wholesale stranded costs.*—(1) *General requirement.* A public utility or transmitting utility will be allowed to seek recovery of wholesale stranded costs only as follows:

(i) No public utility or transmitting utility may seek recovery of wholesale stranded costs if such recovery is explicitly prohibited by a contract or settlement agreement, or by any power sales or transmission rate schedule or tariff.

(ii) No public utility or transmitting utility may seek recovery of stranded costs associated with a new wholesale requirements contract if such contract does not contain an exit fee or other explicit stranded cost provision.

(iii) If wholesale stranded costs are associated with a new wholesale requirements contract containing an exit fee or other explicit stranded cost provision, and the seller under the contract is a public utility, the public utility may seek recovery of such costs, in accordance with the contract, through rates for electric energy under sections 205–206 of the FPA. The public utility may not seek recovery of such costs through any transmission rate for FPA section 205 or 211 transmission services.

(iv) If wholesale stranded costs are associated with a new wholesale requirements contract, and the seller under the contract is a transmitting utility but not also a public utility, the transmitting utility may not seek an order from the Commission allowing recovery of such costs.

(v) If wholesale stranded costs are associated with an existing wholesale requirements contract, if the seller under such contract is a public utility, and if the contract does not contain an exit fee or other explicit stranded cost provision, the public utility may seek recovery of stranded costs only as follows:

(A) If either party to the contract seeks a stranded cost amendment pursuant to a section 205 or section 206 filing under the FPA made prior to the expiration of the contract, and the Commission accepts or approves an amendment permitting recovery of stranded costs, the public utility may seek recovery of such costs through FPA section 205–206 rates for electric energy.

(B) If the contract is not amended to permit recovery of stranded costs as described in paragraph (c)(1)(v)(A) of this section, the public utility may file a proposal, prior to the expiration of the contract, to recover stranded costs through FPA section 205–206 or section 211–212 rates for wholesale transmission services to the customer.

(vi) If wholesale stranded costs are associated with an existing wholesale requirements contract, if the seller under such contract is a transmitting utility but not also a public utility, and if the contract does not contain an exit fee or other explicit stranded cost provision, the transmitting utility may seek recovery of stranded costs through FPA section 211–212 transmission rates.

(vii) If a retail customer becomes a legitimate wholesale transmission customer of a public utility or transmitting utility, *e.g.,* through municipalization, and costs are stranded as a result of the retail-turned-wholesale customer's access to wholesale transmission, the utility may seek recovery of such costs through FPA section 205–206 or section 211–212 rates for wholesale transmission services to that customer.

(2) *Evidentiary demonstration for wholesale stranded cost recovery.* A public utility or transmitting utility seeking to recover wholesale stranded costs in accordance with paragraphs (c)(1) (v) through (vii) of this section must demonstrate that:

(i) It incurred costs to provide service to a wholesale requirements customer or retail customer based on a reasonable expectation that the utility would continue to serve the customer;

(ii) The stranded costs are not more than the customer would have contributed to the utility had the customer remained a wholesale requirements customer of the utility, or, in the case of a retail-turned-wholesale customer, had the customer remained a retail customer of the utility; and

(iii) The stranded costs are derived using the following formula: Stranded Cost Obligation = (Revenue Stream Estimate—Competitive Market Value Estimate) × Length of Obligation (reasonable expectation period).

(3) *Rebuttable presumption.* If a public utility or transmitting utility seeks recovery of wholesale stranded costs associated with an existing wholesale requirements contract, as permitted in paragraph (c)(1) of this section, and the existing wholesale requirements contract contains a notice provision, there will be a rebuttable presumption that the utility had no reasonable expectation of continuing to serve the customer beyond the term of the notice provision.

(4) *Procedure for customer to obtain stranded cost estimate.* A customer under an existing wholesale requirements contract with a public utility seller may obtain from the seller an estimate of the customer's stranded cost obligation if it were to leave the public utility's generation supply system by filing with the public utility a request for an estimate at any time prior to the termination date specified in its contract.

(i) The public utility must provide a response within 30 days of receiving the request. The response must include:

(A) An estimate of the customer's stranded cost obligation based on the formula in paragraph (c)(2)(iii) of this section;

(B) Supporting detail indicating how each element in the formula was derived;

(C) A detailed rationale justifying the basis for the utility's reasonable expectation of continuing to serve the customer beyond the termination date in the contract;

(D) An estimate of the amount of released capacity and associated energy that would result from the customer's departure; and

(E) The utility's proposal for any contract amendment needed to implement the customer's payment of stranded costs.

(ii) If the customer disagrees with the utility's response, it must respond to the utility within 30 days explaining why it disagrees. If the parties cannot work out a mutually agreeable resolution, they may exercise their rights to Commission resolution under the FPA.

(5) A customer must be given the option to market or broker a portion or all of the capacity and energy associated with any stranded costs claimed by the public utility.

(i) To exercise the option, the customer must so notify the utility in writing no later than 30 days after the public utility files its estimate of stranded costs for the customer with the Commission.

(A) Before marketing or brokering can begin, the utility and customer must execute an agreement identifying, at a minimum, the amount and the price of capacity and associated energy the customer is entitled to schedule, and the duration of the customer's marketing or brokering of such capacity and energy.

(ii) If agreement over marketing or brokering cannot be reached, and the parties seek Commission resolution of disputed issues, upon issuance of a Commission order resolving the disputed issues, the customer may reevaluate its decision in paragraph (c)(5)(i) of this section to exercise the marketing or brokering option. The customer must notify the utility in writing within 30 days of issuance of the Commission's order resolving the disputed issues whether the customer will market or broker a portion or all of the capacity and energy associated with stranded costs allowed by the Commission.

(iii) If a customer undertakes the brokering option, and the customer's brokering efforts fail to produce a buyer within 60 days of the date of the brokering agreement entered into between the customer and the utility, the customer shall relinquish all rights to broker the released capacity and associated energy and will pay stranded costs as determined by the formula in paragraph (c)(2)(iii) of this section.

(d) *Recovery of retail stranded costs*—(1) *General requirement.* A public utility may seek to recover retail stranded costs through rates for retail transmission services only if the state regulatory authority does not have authority under state law to address stranded costs at the time the retail wheeling is required.

(2) *Evidentiary demonstration necessary for retail stranded cost recovery.* A public utility seeking to recover retail stranded costs in accordance with paragraph (d)(1) of this section must demonstrate that:

(i) It incurred costs to provide service to a retail customer that obtains retail wheeling based on a reasonable expectation that the utility would continue to serve the customer; and

(ii) The stranded costs are not more than the customer would have contributed to the utility had the customer remained a retail customer of the utility.

Note: Appendices A and B and statements of Commissioners Hoecker and Massey will not be published in the Code of Federal Regulations.

Appendix A—List of Petitioners

Docket Nos. RM95–8–001 and RM94–7–002

Abbreviation	Petitioner
1. AEC & SMEPA	Alabama Electric Cooperative, Inc. and South Mississippi Electric Power Association.
2. AEP	Operating Companies of the American Electric Power System.
3. AL Com	Alabama Public Service Commission.
4. Allegheny	Allegheny Power Service Corporation.
5. AL Municipal	Alabama Municipal Electric Authority.
6. American Forest & Paper	American Forest & Paper Association.
7. AMP-Ohio	American Municipal Power-Ohio, Inc. and Indiana Municipal Power Agency.
8. Anaheim	Cities of Anaheim, Azusa, Banning, Colton and Riverside, California.
9. APPA	American Public Power Association.
10. AR Com	Arkansas Public Service Commission.
11. Arkansas Cities	Arkansas Cities and Farmers Electric Cooperative.
12. Associated EC	Associated Electric Cooperative, Inc.
13. Atlantic City	Atlantic City Electric Company.
14. Basin EC	Basin Electric Power Cooperative.
15. Blue Ridge	Blue Ridge Power Agency, Northeast Texas Electric Cooperative, Inc., Sam Rayburn G&T Electric Cooperative, Inc., and Tex-La Electric Cooperative of Texas, Inc.
16. BPA	Bonneville Power Administration.
17. Cajun	Ralph R. Mabey, Chapter II Trustee for Cajun Electric Power Cooperative, Inc.
18. California DWR	California Department of Water Resources.
19. Carolina P&L	Carolina Power & Light Company.
20. CCEM	Coalition for a Competitive Electric Market (consisting of Coastal Electric Services Company, Destec Power Services, Inc., Electric Clearinghouse, Inc., Enron Power Marketing, Inc., Equitable Power Services Company, KCS Power Marketing, Inc., MidCon Power Services Corp. and Vitol Gas & Electric Services, Inc).
21. Centerior	Centerior Energy Corporation.
22. Central Illinois Light	Central Illinois Light Company.
23. Central Minnesota Municipal	Central Minnesota Municipal Power Agency.
24. Central Montana EC	Central Montana Electric Power Cooperative, Inc.
25. Cleveland	Cleveland Public Power.
26. CO Consumers Counsel	Colorado Office of Consumer Counsel.
27. Coalition for Economic Competition.	Coalition for Economic Competition Consisting of Consolidated Edison Company of New York, Inc., General Public Utilities Corporation, Illinois Power Company, Long Island Lighting Company, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Northeast Utilities, and Rochester Gas and Electric Corporation.
28. ConEd	Consolidated Edison Company of New York, Inc.
29. Connecticut DEP	State of Connecticut Department of Environmental Protection.
30. Consumers Power	Consumers Power Company.
31. Cooperative Power	Cooperative Power.
32. CSW Operating Companies	Central Power and Light, West Texas Utilities Company, Public Service Company of Oklahoma and Southwestern Electric Power Company.
33. CVPSC	Central Vermont Public Service Corporation.
34. Dairyland	Dairyland Power Cooperative.
35. Dalton	City of Dalton, Georgia.
36. Detroit Edison	Detroit Edison Company.
37. Dispute Resolution	Communications and Energy Dispute Resolution Associates.
38. Duquesne	Duquesne Light Company.
39. EEI	Edison Electric Institute.
40. EGA	Electric Generation Association.
41. El Paso	El Paso Electric Company.
42. ELCON	Electricity Consumers Resource Council, American Iron and Steel Institute, Chemical Manufacturers Association and Council of Industrial Boiler Owners.
43. Entergy	Entergy Services, Inc.
44. EPRI	Electric Power Research Institute.
45. FL Com	Florida Public Service Commission.
46. Florida Power Corp	Florida Power Corporation.
47. FMPA	Florida Municipal Power Agency.

Abbreviation	Petitioner
48. FPL	Florida Power & Light Company.
49. Freedom Energy Co	Freedom Energy Corporation, LLC.
50. Hoosier EC	Hoosier Energy Rural Electric Cooperative.
51. IA Com	Iowa Utilities Board.
52. IL Com	Illinois Commerce Commission.
53. IL Industrials	Illinois Industrial Energy Consumers.
54. Illinois Power	Illinois Power Company.
55. IMPA	Indiana Municipal Power Agency.
56. IN Com	Indiana Utility Regulatory Commission.
57. IN Consumer	Indiana Office of Utility Consumer Counselor.
58. Indianapolis POL	Indianapolis Power & Light Company.
59. IN Industrials	Citizens Action Coalition of Indiana, Inc., Indiana Industrial Energy Consumers, Inc. and Indianapolis Power & Light Company.
60. Joint Commenters	Joint Commenters Supporting Clear Air and Fair Corporation.
61. KCPL	Kansas City Power & Light Company.
62. LEPA	Louisiana Energy and Power Authority.
63. Local Furnishing Utilities	Local Furnishing Utilities (Long Island Lighting Company, Nevada Power Company, San Diego Gas & Electric Company and Tuscon Electric Power Company).
64. MA Municipals	Twenty Four Massachusetts Municipals.
65. Maine Public Service	Maine Public Service Company.
66. MI Com	Michigan Public Service Commission and New Hampshire Public Utilities Commission.
67. Michigan Systems	Michigan Public Power Agency, Michigan South Central Power Agency, and Wolverine Power Supply Co-operative, Inc.
68. Minnesota P&L	Minnesota Power & Light Company.
69. MN DPS	Minnesota Department of Public Service and Minnesota Public Utilities Commission.
70. MO/KS Coms	Missouri Public Service Commission and Kansas Corporation Commission.
71. Montana Power	Montana Power Company.
72. Montana-Dakota Utilities	Montana-Dakota Utilities Company.
73. Multiple Intervenors	Multiple Intervenors.
74. NARUC	National Association of Regulatory Utility Commissioners.
75. NASUCA	National Association of State Utility Consumer Advocates.
76. NCMPA	North Carolina Municipal Power Agency Number 1.
77. NE Public Power District	Nebraska Public Power District.
78. NIMO	Niagara Mohawk Power Corporation.
79. NJ BPU	New Jersey Board of Public Utilities.
80. North Jersey	North Jersey Energy Associates.
81. NRECA	National Rural Electric Cooperative Association.
82. NU	Northeast Utilities Service Company.
83. Nuclear Energy Institute	Nuclear Energy Institute.
84. Nucor	Nucor Corporation.
85. NWRTA	Northwest Regional Transmission Association.
86. NY AG	New York State Attorney General.
87. NY Com	Public Service Commission of the State of New York.
88. NY Municipals	Municipal Electric Utilities Association of New York States.
89. NY Utilities	Consolidated Edison Company of New York, Inc., Long Island Lighting Company, New York State Electric & Gas Corporation, and Rochester Gas and Electric Corporation.
90. NYPP	New York Power Pool.
91. NYSEG	New York State Electric & Gas Corporation.
92. Occidental Chemical	Occidental Chemical Corporation.
93. Oglethorpe	Oglethorpe Power Corporation.
94. OH Com	Public Utilities Commission of Ohio.
95. OH Consumers' Counsel	Ohio Office of Consumers' Counsel.
96. Ohio Valley	Ohio Valley Electric Corporation and Indiana-Kentucky Electric Corporation.
97. Oklahoma G&E	Oklahoma Gas and Electric Company Inc.
98. Ontario Hydro	Ontario Hydro.
99. PA Com	Pennsylvania Public Utility Commission.
100. PA Coops	Pennsylvania Rural Electric Association and Allegheny Electric Cooperative, Inc.
101. PA Munis	Pennsylvania Municipal Electric Association.
102. PacifiCorp	PacifiCorp.
103. PSE&G	Public Service Electric and Gas Company.
104. PSNM	Public Service Company of New Mexico.
105. Public Service Co of CO	Public Service Company of Colorado.
106. Puget	Puget Sound Power & Light Company.
107. Redding	City of Redding, California.
108. San Francisco	City and County of San Francisco.
109. Santa Clara	City of Santa Clara, California.
110. SBA	United States Small Business Administration, Office of Advocacy.
111. SC Public Service Authority	South Carolina Public Service Authority.
112. SoCal Edison	Southern California Edison Company.
113. Southern	Southern Company Services, Inc.
114. Southwestern	Southwestern Public Service Company.
115. Speciality Steel	Speciality Steel Industry of North America.
116. Suffolk County	Suffolk County (New York) Electric Agency.
117. SWRTA	Southwest Regional Transmission Association.

Abbreviation	Petitioner
118. Tallahassee	City of Tallahassee, Florida.
119. TANC	Transmission Agency of Northern California.
120. TAPS	Transmission Access Policy Study Group.
121. TDU Systems	Transmission Dependent Utility Systems.
122. Texaco	Texaco Inc.
123. Tucson Power	Tucson Electric Power Company.
124. Turlock	Turlock Irrigation District.
125. TX Com	Public Utility Commission of Texas.
126. Umatilla EC	Umatilla Electric Cooperative.
127. Union Electric	Union Electric Company.
128. Utilities For Improved transition.	Utilities For an Improved Transition (consisting of Associated Electric Cooperative, Inc., Boston Edison Company, Central Vermont Public Service Corporation, Montaup Electric Company, Wisconsin Electric Power Company, and Wisconsin Public Service Corporation).
129. VA Com	Staff of the Virginia State Corporation Commission.
130. Valero	Valero Power Services Company.
131. VEPCO	Virginia Electric and Power Company.
132. VT DPS	Vermont Department of Public Service.
133. Wabash	Wabash Valley Power Association, Inc.
134. Washington Water Power	Washington Water Power Company.
135. WI Com	Public Service Commission of Wisconsin.
136. Wisconsin Municipals	Municipal Electric Utilities of Wisconsin.
137. WY Com	Public Service Commission of Wyoming.

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I. Common Service Provisions

1 Definitions

1.1 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.

1.2 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 until amended by the Transmission Provider or modified by the Commission.

1.3 Application: A request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

1.4 Commission: The Federal Energy Regulatory Commission.

1.5 Completed Application: An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

1.6 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.

1.7 Curtailment: A reduction in firm or non-firm transmission service in response to a transmission capacity shortage as a result of system reliability conditions.

1.8 Delivering Party: The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.9 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.

1.10 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.

1.11 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.

1.12 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.

1.13 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.

1.14 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.

1.15 Interruption: A reduction in non-firm transmission service due to economic reasons pursuant to Section 14.7.

1.16 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 the Tariff and calculated on a rolling twelve month basis.

1.17 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.

1.18 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.

1.19 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.

1.20 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.

1.21 Network Integration Transmission Service: The transmission service provided under Part III of the Tariff.

1.22 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.

1.23 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.

1.24 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.

1.25 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.

1.26 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.

1.27 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.

1.28 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.

1.29 Part I: Tariff Definitions and Common Service Provisions contained in Sections 2 through 12.

1.30 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.

1.31 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.

1.32 Parties: The Transmission Provider and the Transmission Customer receiving service under the Tariff.

1.33 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.

1.34 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.

1.35 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.

1.36 Power Purchaser: The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

1.37 Receiving Party: The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

1.38 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.

1.39 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.

1.40 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.

1.41 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.

1.42 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.

1.43 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.

1.44 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.

1.45 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.

1.46 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.

1.47 Transmission Provider's Monthly Transmission System Peak: The maximum firm usage of the Transmission Provider's Transmission System in a calendar month.

1.48 Transmission Service: Point-To-Point Transmission Service provided under Part II of the Tariff on a firm and non-firm basis.

1.49 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 Transmission 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 one-year 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 a competing request by any new Eligible Customer and to pay the current just and reasonable rate, as approved by the Commission, for such service. 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 one-year or longer.

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 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, and (iv) Operating Reserve—Supplemental. 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.

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 and 6) 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 3.6 below list the six 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 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.

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 § 37 of the Commission's regulations (Open Access Same-Time Information System and Standards of Conduct for Public Utilities). In the event available transmission 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.

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 a power pool or Regional Transmission Group also agrees to provide comparable transmission service to the members of such power pool and Regional Transmission Group 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 C.F.R. § 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

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. In addition, 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.

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:

(A) 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

(B) 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 transmission 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: 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 reserved service. Reservations for Short-Term Firm Point-To-Point Transmission Service will be conditional based upon the length of the requested transaction. 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 transmission 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. 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. After the conditional reservation deadline, service will commence pursuant to the terms of Part II of the Tariff. 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.

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 more economically by redispatching the Transmission Provider's resources than through constructing Network Upgrades, it shall do so, provided that the Eligible Customer agrees to compensate the Transmission Provider pursuant to the terms of Section 27 . 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, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. 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. 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 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 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.

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 *10:00 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 10:00 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 transmission 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 to reservations with a longer duration of service. In the event the Transmission System is constrained, competing requests of 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 [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 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 *2:00 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 2:00 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. 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, or (4) transmission service for Network Customers from non-designated resources. 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 Transmission Capability: A description of the Transmission Provider's specific methodology for assessing available transmission capability posted on the Transmission Provider's OASIS (Section) is contained in Attachment of the Tariff. In the event sufficient transmission 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: 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, 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 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.

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; and

e. 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; and

(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.

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 transmission 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 , 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 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.

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 2:00 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 Transmission Capability: Following receipt of a tendered schedule the Transmission Provider will make a determination on a non-discriminatory basis of available transmission 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

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, 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 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. 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 transmission 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.

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 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 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 the Reseller shall not exceed the higher of (i) the original rate paid by the Reseller, (ii) the Transmission Provider's maximum rate on file at the time of the assignment, or (iii) the Reseller's opportunity cost capped at the Transmission Provider's cost of expansion. 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. A Reseller should notify the Transmission Provider as soon as possible after any assignment or transfer of service occurs but in any event, notification must be provided prior to any provision of service to the Assignee. 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 Parties through an amendment to the Service Agreement.

23.3 Information on Assignment or Transfer of Service: In accordance with Section 4, Resellers may use the Transmission Provider's OASIS to post transmission capacity available for resale.

24 Metering and Power Factor Correction at Receipt and Delivery Point(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 more economically by redispatching the Transmission Provider's resources than by building new facilities or upgrading existing facilities 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 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 transmission capability. The Transmission Provider shall include the Network Customer's Network Load in its Transmission System planning and shall, consistent with Good Utility Practice, endeavor to construct and place into service sufficient transmission capacity 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. 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.

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.

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), which shall include, for each Network Resource:

—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
—Description of purchased power designated as a Network Resource including source of supply, Control Area location, transmission arrangements and delivery point(s) to the Transmission Provider's Transmission System;

(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; and

(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.

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 by a request for modification of service pursuant to an Application under Section 29.

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 at any time but should provide notification to the Transmission Provider as soon as reasonably practicable.

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.

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 constructed by the Network Customer subsequent to the Service Commencement Date under Part III of the Tariff, the Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with the Transmission Provider. Calculation of the credit 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 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 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. 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 . 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. 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.

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. 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.

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 North American Electric Reliability Council (NERC) and the [applicable regional reliability council], (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 NERC and the [applicable regional reliability council] requirements. 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 Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation 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 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 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) 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 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 shall establish a deviation band of +/−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). Parties should attempt to eliminate energy imbalances within the limits of the deviation band within thirty (30) days or within such other reasonable period of time as is generally accepted in the region and consistently adhered to by the Transmission Provider. If an energy imbalance is not corrected within thirty (30) days or a reasonable period of time that is generally accepted in the region and consistently adhered to by the Transmission Provider, the Transmission Customer will compensate the Transmission Provider for such service. Energy imbalances outside the deviation band will be subject to charges to be specified by the Transmission Provider. The charges for Energy Imbalance Service are set forth below.

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. 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. 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.

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 (1) 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 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 Transmission Capability

To be filed by the Transmission Provider.

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

Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities. Docket No. RM95–8–001.

Recovery of Stranded Costs by Public Utilities and Transmitting Utilities. Docket No. RM94–7–002.

(Issued March 4, 1997)

HOECKER, Commissioner, *dissenting in part:*

I. General Observations

Today's rehearing order makes Order No. 888 ripe for judicial review and largely concludes the most ambitious generic rulemaking effort in this agency's history. The scores of specific policy calls embodied in Order No. 888–A represent reasoned decisionmaking that, in its sheer level of detail, takes us to the outer limits of our ability to predict or control the proper future operation of the market. Still, the timeliness of this order ought to be welcomed. Having satisfactorily demonstrated that the fundamental rules governing a network as complex and important as the Nation's transmission grid can be changed and made to work, the Commission will henceforth be engaged in implementing open access tariffs and dealing with the direct and indirect consequences of bulk power competition. The mantle of major policymaking now shifts to the states and to the U.S. Congress.

During this proceeding, the industry has continued to evolve. In ten short months, merger and acquisition activity has increased dramatically and may foretell a more significant reconfiguration in the future. The concept of an independent system operator has attained significant credibility as a possible way to throttle market power, ensure system reliability, and rationalize the bulk power market. Retail access and customer choice suddenly dominate the restructuring debate, although the future competitive retail power market still defies prediction. The demarcation between state and federal jurisdiction is actively being tested. And, as the implications of full stranded cost recovery are being thought through within the industry, companies are also trying to diagnose and address their other competitive vulnerabilities. These remarkable and largely unforeseeable changes counsel against the temptation among public policymakers to over-plan and over-prescribe the future of power markets.

II. Partial Dissent

In Order No. 888, the Commission announced that it would be the ''primary forum'' for stranded cost claims in those instances where a retail power customer turns wholesale wheeling customer, usually through a municipalization. I dissented from that portion of the Final Rule because I concluded that the Commission's decision to take responsibility for stranded costs arising from municipalization was insupportable as a matter of either policy or law. As the ''primary forum'' for recovery of these costs, the Commission will be required to second-guess certain state retail stranded cost determinations, even when state regulators and state statutes address the issue sufficiently. This would, in my estimation, encourage forum shopping and fundamentally contradict our approach in the retail wheeling situation, where retail stranded costs are subject to Commission action *only* if the state regulatory body lacks authority to deal with this important transitional issue. I continue to hold these views.

The majority has bolstered its position today with additional arguments connecting the Commission's actions in Order No. 888 to the wholesale status of new municipal power customers. While inventive, the majority rests its theory of jurisdiction on a tenuous theory of cause and effect. Briefly, the rehearing order distinguishes wholesale stranded costs from retail stranded costs not by the nature of the *costs,* but by the status of the *customer* (*i.e.,* a wholesale transmission services customer versus a retail transmission services customer) with whom the costs are associated. It further contends that jurisdiction over stranded costs depends on ''whether the transmission tariffs used by the customer to escape its former power supplier * * * were required by this Commission or by a state commission''. The majority states that this Commission will serve as the ''primary forum'' for stranded cost recovery only where there exists a *direct nexus* between the availability and use of FERC's open access transmission tariffs and the stranding of costs.

I am not persuaded by the rationale supplied by my colleagues. I continue to believe that municipalization, like retail wheeling, would be unavailable to retail customers as a competitive supply alternative *but for* state action. In both instances, it is state law that provides the legal means for retail customers to gain access to FERC-jurisdictional transmission tariffs. In the final analysis, I am not persuaded that the public interest is served by the majority's intrusion into an area potentially policed under state law, notwithstanding the Commission's strong commitment to full cost recovery.

In today's order, the Commission also broadens its ''primary forum'' approach to include situations involving the expansion of *existing* municipal utility systems, for example through annexation of retail customer load or additional service territory. I contend, however, that the ''primary forum'' approach is no more appropriate for municipal annexations than it is for new municipalizations.

The discussion of this issue in Order No. 888–A heightens my previous concerns in a number of ways. First, the majority's position is based on the alleged similarities between the creation of a *new* municipal utility system and the expansion of an *existing* municipal utility system. In both cases, they argue, a nexus exists between the municipalization and Commission-required transmission access; the salient connection is the use that the new wholesale customer makes of the former supplying utility's transmission system. If one were to assume the correctness of the majority's municipalization approach, it would make sense to limit its stranded cost recovery provisions to such circumstances only. But, there are two more compelling factors that determine the legitimacy of any stranded cost approach. First, like retail wheeling, all municipalizations, whether new or annexations, occur pursuant to state law. As already discussed, state action allows retail customers to aggregate load and, through municipalization, gain access to FERC-jurisdictional transmission tariffs. Second, the risk of annexation (and with it the loss of retail load) existed long before enactment of the Energy Policy Act or implementation of Order No. 888. I believe these factors argue for treatment of all costs incurred to serve retail load and stranded pursuant to state action—whether by retail wheeling, new municipalization, or annexation—by the same state regulatory body. I do not dispute, however, that the Commission should step in when states fail to ensure some level of stranded cost recovery, thereby creating a regulatory gap.

The rehearing order has an additional problem. It states that the Commission will not necessarily be the ''primary forum'' for stranded cost recovery in *all* cases of municipal annexation. The majority's new willingness to decide stranded costs arising from the annexation of new load will therefore require a finding that the existing municipality will use the transmission system of the annexed retail customers' former supplier to provide service to the annexed load. This approach is necessitated by the ''nexus'' theory of jurisdiction over the underlying stranded costs, and it represents a novel theory of law. Moreover, the administrative difficulties associated with this particular fact-finding will be extensive. An existing municipality already has transmission and generation service arrangements in place. With access to additional generation resources now available in the newly competitive wholesale power market, a municipality ultimately may be served by a number of suppliers, possibly in addition to its own resources. In such circumstances, the difficulty in determining which generation resources, and hence which transmission services, are being used to supply service to the annexed customers in particular may be virtually insurmountable. Under the nexus test, the Commission must settle that matter preliminarily just to decide whether it is the proper forum for addressing the costs stranded by an annexation.

To compound this practical problem, the majority's commitment to give ''great weight to a state's view'' of what stranded costs are recoverable under state law in these circumstances, and to deduct the amount of state stranded cost awards from the amount that a utility may seek to recover from this Commission, is likely to prove a hollow promise. Such deference would require a prior stranded cost determination on the merits by state regulators, despite the majority's instruction to the parties to raise all stranded cost claims under the municipalization scenario before this Commission ''in the first instance.''

Deference in this context is a slippery proposition for other reasons, too. Naturally, states may perceive equity considerations, cost causation principles, [1] and market risk factors[2] differently than the Commission, and consequently they may not share the Commission's view that utilities are entitled to full recovery of stranded costs here. Because of this potential difference of opinion, I suspect that the amount of deference that the Commission provides to the states may be directly proportional to the level of stranded cost recovery that states grant the utilities.

In sum, the majority's ingenious attempt to federalize stranded cost claims arising from municipalization, while admirable in terms of the need to resolve transition cost issues expeditiously, is more likely to cause greater uncertainty and more argument about the appropriate standard to apply than it is to promote settlement of the matter.

I therefore respectfully dissent in small part to Order No. 888–A.

James J. Hoecker,

Commissioner.

Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities. Docket No. RM95–8–001.

Recovery of Stranded Costs by Public Utilities and Transmitting Utilities. Docket No. RM94–7–002.

Order No. 888–A

(Issued March 4, 1997)

MASSEY, Commissioner, *dissenting in part:*

I dissent in part, from this otherwise excellent rule, on a single issue. I continue to believe, as I stated in my dissent to Order No. 888, that the Commission should treat stranded costs arising from retail competition and municipalizations similarly.

Municipalization occurs under state rather than federal law. The majority's decision in Order No. 888 that FERC should be the primary forum for addressing the recovery of stranded costs caused by municipalization boldly and unnecessarily preempts legitimate state authority. Today's order perpetuates and compounds this error by extending federal preemption to stranded costs arising from municipal annexations as well.

Many state commissions have express legislative authority to address these issues and should not be prohibited from doing so by federal regulators. It is only when a state commission does not have the authority, or has the authority and fails to use it, that the Commission should be available as a stranded cost recovery forum of last resort.

On this one issue, I respectfully dissent.

William L. Massey,

Commissioner.

[FR Doc. 97–5767 Filed 3–13–97; 8:45 am]

BILLING CODE 6717–01–P

[1] Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 636–C, 78 FERC ¶ 61,186 (1997).

[2] Mechanisms for Passthrough of Pipeline Take-or-Pay Buyout and Buydown Costs, Order No. 528–A, 54 FERC ¶ 61,095 (1991).

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 37

[Docket No. RM95–9–001; Order No. 889–A]

Open Access Same-Time Information System and Standards of Conduct

Issued March 4, 1997.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final Rule; order on rehearing.

SUMMARY: The Federal Energy Regulatory Commission is revising its policy on posting discounts to be consistent with changes in the discount policy that we simultaneously are implementing in Order No. 888–A. Additionally, we are making other minor revisions to 18 CFR Part 37—which contains rules establishing and governing transmission information networks and standards of conduct—to be responsive to arguments made on rehearing and to make the regulations operate more smoothly.

In addition, the Commission requests that the How Working Group propose the necessary changes in the Standards and Protocols document and the Data Dictionary by June 2, 1997 to address four issues.

EFFECTIVE DATE: This rule is effective on May 13, 1997.

FOR FURTHER INFORMATION CONTACT:

Marvin Rosenberg (Technical Information), Office of Economic Policy, Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, DC 20426, (202) 208–1283.

William C. Booth (Technical Information), Office of Electric Power Regulation, Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, DC 20426, (202) 208–0849.

Gary D. Cohen (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, DC 20426, (202) 208–0321.

SUPPLEMENTARY INFORMATION: In addition to publishing the full text of this document in the Federal Register, the Commission also provides all interested persons an opportunity to inspect or copy the contents of this document during normal business hours in the Public Reference Room at 888 First Street, N.E., Washington, D.C. 20426.

The Commission Issuance Posting System (CIPS), an electronic bulletin board service, provides access to the texts of formal documents issued by the Commission. CIPS is available at no charge to the user and may be accessed using a personal computer with a modem by dialing 202–208–1397 if dialing locally or 1–800–856–3920 if dialing long distance. To access CIPS, set your communications software to 19200, 14400, 12000, 9600, 7200, 4800, 2400, or 1200 bps, full duplex, no parity, 8 data bits and 1 stop bit. The full text of this order will be available on CIPS in ASCII and Wordperfect 5.1 format. CIPS user assistance is available at 202–208–2474.

CIPS is also available through the Fed World system. Telnet software is required. To access CIPS via the Internet, point your browser to the URL address: http://www.fedworld.gov and select the ''Go to the FedWorld Telnet Site'' button. When your Telnet software connects you, log onto the FedWorld system, scroll down and select FedWorld by typing: 1 and at the command line then typing: /go FERC. FedWorld may also be accessed by Telnet at the address fedworld.gov.

Finally, the complete text on diskette in WordPerfect format may be purchased from the Commission's copy contractor, La Dorn Systems Corporation. La Dorn Systems Corporation is also located in the Public Reference Room at 888 First Street, N.E., Washington, D.C. 20426.

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I. Introduction

In this order, the Commission addresses the requests for rehearing of Order No. 889, our final rule requiring public utilities that own, control, or operate facilities used for the transmission of electric energy in interstate commerce to create or participate in an Open Access Same-Time Information System (OASIS) site in conformance with the requirements set out in 18 CFR Part 37.[1] Those requirements also obligate public utilities subject to the rule to implement standards of conduct to functionally separate transmission and wholesale merchant functions.

For the reasons stated, we will grant rehearing, in part, and adopt several suggested revisions to the OASIS final rule, but will, in main part, deny rehearing and retain the OASIS final rule as promulgated in Order No. 889. In addition, we request that the How Working Group propose changes to the Standards and Protocols document and the Data Dictionary by June 2, 1997 to address four issues described below.

II. Background

In Order No. 889, the Commission promulgated a final rule (OASIS Final Rule) requiring Transmission Providers[2] to implement the legal and policy determinations made concurrently in Order No. 888, the final rule on open access transmission (Open Access Final Rule).[3] Under Order No. 889, the OASIS Final Rule applies to any transmission service offered under the Open Access Final Rule *pro forma* tariff, including service both to wholesale Transmission Customers and to retail Transmission Customers that are able to receive unbundled retail transmission service and to any entity required to provide such service.

Under the OASIS Final Rule, Transmission Providers are required to establish or participate in an OASIS that meets certain requirements and must comply with prescribed standards of conduct. The standards of conduct are designed to prevent employees of a public utility (or any employees of its affiliates) engaged in wholesale merchant functions (wholesale sales of electricity for resale in interstate commerce) from obtaining preferential access to pertinent transmission-related information.

To this end, the standards of conduct, set out in the Commission's regulations at 18 CFR 37.4, require companies to separate their transmission operations/reliability functions from their wholesale marketing/merchant functions. They are intended to prevent transmission system operators from providing wholesale merchant employees or wholesale merchant employees of affiliates with transmission-related information not available to all customers at the same time (through public posting on the OASIS).

The OASIS Final Rule describes what information must be posted on an OASIS, what procedures must be followed in responding to requests for transmission service, and references the Commission's accompanying Standards and Protocols document adopted by the Commission to ensure that information is to be posted on an OASIS in a uniform manner.[4] Transmission Providers are required to provide on an OASIS, in a uniform manner, certain types of information concerning the status of their transmission systems. The provisions of the OASIS Final Rule are intended to work together to ensure that Transmission Customers[5] have access to transmission information, through electronic means, that will enable them to obtain comparable, open access transmission service on a non-discriminatory basis.

Order No. 889 established Phase I OASIS rules that required the creation of a basic OASIS by November 1, 1996 (subsequently extended until January 3, 1997).[6] We are appreciative of the ongoing efforts of the How Working Group and the What Working Group in helping to develop the OASIS Standards and Protocols and in helping to resolve numerous difficult OASIS implementation issues.[7] We also, despite setbacks encountered by some public utilities, are appreciative of the hard work of the entire electric industry in meeting the ambitious schedule for OASIS implementation prescribed in Order No. 889.

Order No. 889 also explained that Phase I implementation would be followed by Phase II procedures

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[1] Open Access Same-Time Information System and Standards of Conduct, Final Rule, Order No. 889, FERC Stats. & Regs. ¶ 31,037, 61 FR 21,737 (1996). Since issuance of Order No. 889, we have issued two additional orders. These orders: (1) revise the standards and communication protocols for OASIS nodes; and (2) extend the date for commencing Phase I OASIS operations and complying with the standards of conduct. *See infra* notes 4, 6, respectively.

[2] Order No. 889 and the OASIS regulations at 18 CFR 37.3 define a ''Transmission Provider'' as any public utility that owns, operates, or controls facilities used for the transmission of electric energy in interstate commerce. This same definition applies to our use of this term in this order.

[3] Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, Final Rule, FERC Stats. & Regs. ¶ 31,632, 61 FR 21,540 (1996), *order on reh'g*, Order No. 888–A,—FERC ¶ —,—(1997).

[4] *See* Open Access Same-Time Information System and Standards of Conduct, Order Issuing Revised OASIS Standards and Protocols Document, 76 FERC ¶ 61,243, 61 FR 50,116 (1996), where the Commission revised the Standards and Protocols document that accompanied Order No. 889.

[5] Order No. 889 and the OASIS regulations at 18 CFR 37.3 define a ''Transmission Customer'' as any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service. This same definition applies to our use of this term in this order.

[6] See Open Access Same-Time Information System and Standards of Conduct, Order Granting Request for Extension of Time, 76 FERC ¶ 61,305 (1996).

[7] The How Working Group and its companion working group, the What Working Group, are industry-led groups, with diverse industry and customer representatives, working to reach consensus on OASIS-related issues. *See* OASIS Final Rule, 61 FR at 21,740, n.13, for a fuller description of both working groups and their activities.

whereby the Commission, with ongoing industry participation, will continue to refine and further develop the requirements for a fully functional OASIS.[8]

Requests for rehearing relating to Order No. 889 were filed by over 40 interested persons. These include 37 requests for rehearing that collectively list both Order Nos. 888 and 889 in their captions and ten requests for rehearing that are aimed exclusively at Order No. 889.[9] Several of the issues raised on rehearing that implicate both Order Nos. 888 and 889 are addressed more fully in Order No. 888–A, which is being issued contemporaneously with this order.[10]

III. Public Reporting Burden

This order on rehearing adopts a number of small changes, more fully elaborated in Section IV.E.8 below, to be consistent with the Commission's revised discount policy being announced in Order No. 888–A. In addition, we also are making nine minor revisions to the OASIS Final Rule and direct the How Working Group to propose changes to the Standards and Protocols document addressing four additional issues. We find, after reviewing these revisions, that they do not, on balance, increase the public reporting burden.

The OASIS Final Rule contained an estimated annual public reporting burden based on the requirements of the Final Rule and consideration of comments from interested persons.[11] Using the burden estimate contained in the OASIS Final Rule as a starting point, we evaluated the public burden estimate contained in the OASIS Final Rule in light of the revisions contained in this order and assessed whether this estimate needed revision. We have concluded, given the minor nature of the revisions, and their offsetting nature, that our estimate of the public reporting burden of this order on rehearing remains unchanged from our original estimate of the public reporting burden contained in the OASIS Final Rule. The Commission has conducted an internal review of this conclusion and has assured itself, by means of its internal review, that there is specific, objective support for this information burden estimate. Moreover, the Commission has reviewed the collection of information required by the OASIS Final Rule as revised by this order on rehearing and has determined that the collection of information is necessary and conforms to the Commission's plan, as described in this order, for the collection, efficient management, and use of the required information.

Persons wishing to comment on the collections of information required by this order on rehearing should direct their comments to the Desk Officer for FERC, Office of Management and Budget, Room 3019 NEOB, Washington, D.C. 20503, phone 202–395–3087, facsimile: 202–395–7285 or via the Internet at hillier__t@a1.eop.gov. Comments must be filed with the Office of Management and Budget within 30 days of publication of this document in the Federal Register. Three copies of any comments filed with the Office of Management and Budget also should be sent to the following address: Ms. Lois Cashell, Secretary, Federal Energy Regulatory Commission, Room 1A, 888 First Street, N.E., Washington, D.C. 20426. For further information, contact Michael Miller, 202–208–1415.

IV. Discussion

A. Overview of Revisions made in this Order

In this order on rehearing of Order No. 889, the Commission has implemented a new discounting policy, adopted and described in detail in Order No. 888–A. This new discount policy necessitates a number of changes to the Standards of Conduct and OASIS posting requirements:

(1) We are deleting §§ 37.4(b)(5)(v) and 37.4(b)(5)(vi).

(2) We are adding a provision now designated as § 37.6(c)(3) to require, among other things, that any offer of a discount for basic transmission service must be announced to all potential customers solely by posting on the OASIS.

(3) We are revising § 37.6(c)(4) to no longer treat the posting of transmission service transactions involving the Transmission Provider's (or any affiliate's) merchant function any differently from the posting of transactions involving non-affiliates except that transactions involving the Transmission Provider's wholesale merchant function or affiliates must be identified.

(4) We are adding a provision now designated as § 37.6(d)(2) to require, among other things, that any offer of a discount for ancillary service provided by the Transmission Provider in support of its provision of basic transmission service must be announced to all potential customers solely by posting on the OASIS.

(5) We are revising § 37.6(d)(3) on ancillary services consistent with item 3 above.

(6) We are revising § 37.6(e)(1)(i) to require that, except for next-hour service, requests for transmission and ancillary service must be posted prior to the Transmission Provider responding to these requests.

(7) We are adding a provision, now designated as § 37.6(e)(1)(ii), that during Phase I, while requests for next-hour service need to be posted as soon as possible and in any event within one hour of receiving the request, they need not be posted prior to being acted on.

(8) We are adding a provision, at § 37.6(e)(1)(iii), that provides that in the event that a discount is being requested for ancillary services that are not in support of the Transmission Provider's provision of basic transmission service, such request need not be posted on the OASIS.

(9) We are renumbering § 37.6(e)(1)(ii) as § 37.6(e)(1)(iv) and are expanding the information required to be posted on the status of requests for transmission and ancillary service.

(10) We are deleting the provision formerly found in § 37.6(e)(1)(iii) and are revising § 37.6(e)(3)(i) because we no longer will allow the identity of parties to transactions to be masked.

Additionally, we believe that any ''negotiation'' [12] between a Transmission Provider and a potential customer should take place on the OASIS, and should be visible to all market participants, and we will revise our regulations to accomplish this as soon as practicable. To this end, we direct the How Working Group, by no later than June 2, 1997, to propose: (1) any changes that might be necessitated to the Standards and Protocols document; and (2) the earliest date when the industry can meet such a requirement during Phase I.

We also are making nine minor revisions to 18 CFR Part 37. These include: (1) amending the definition of wholesale merchant function in § 37.3; (2) amending §§ 37.4(b)(5)(iii) and 37.6(g)(4) to require Transmission Providers to post on the OASIS the information that they already are required to keep, detailing the circumstances and manner in which they exercise their discretion under any terms of the tariff; (3) substituting the phrase ''sales made to any person for

[8] In the OASIS Final Rule, 61 FR at 21,762, we requested that the industry prepare a report on Phase II issues due on or before August 4, 1997 (seven months from January 3, 1997, the revised compliance date for Phase I implementation).

[9] The requests for rehearing for AK Cities, AL EC, AL MEA, Basin EC, Cajun, Central P&L, Central Montana EC, Cooperative Power, FPL, Florida Power Corp, Hoosier EC, NWRTA, Santa Clara, and SWRTA raised no direct 889 issues. The names and abbreviations of all interested persons who filed requests for rehearing of Order No. 889 (or a combined request for rehearing of Order Nos. 888 and 889) are listed in Attachment 1.

We also note that, in various places in this order, we identify issues that were raised in requests for rehearing of Order No. 889, or that were identified as pertaining to Order No. 889, that, in our judgment, really seek rehearing of matters relating to Order No. 888. They are therefore decided in Order No. 888–A.

[10] *See* Order No. 888–A.

[11] No comments were filed in objection to the public burden estimate contained in the OASIS Final Rule.

[12] ''Negotiation'' would only take place if the Transmission Provider or potential customer seeks prices below the ceiling prices set forth in the tariff.

resale made by the wholesale merchant function or any affiliate'' for the phrase ''wholesale purchases or sales made on behalf of its own power customers, or those of an affiliate'' in § 37.4(b)(5)(iv), to be consistent with the revised definition of ''wholesale merchant function'; (4) amending § 37.6(b)(1) to clarify the meaning of the term ''interconnection'' as used in the definition of posted path; (5) amending § 37.6(b)(3)(ii) to clarify that firm available transmission capability (ATC) and nonfirm ATC for unconstrained posted paths must be separately posted; (6) amending § 37.6(e) to clarify that the provision applies to requests for ancillary service and that requests for service must be posted before the Transmission Provider responds to the request; (7) amending § 37.6(g)(3) to require that notices of transfers of personnel posted on the OASIS as described in § 37.4(b)(2) remain available for the same time period as audit information in § 37.7(b); (8) amending § 37.7(b) to shorten, from 90 days to 20 days, the time during which ATC/total transmission capability (TTC) postings must remain available for download on the OASIS (the data will, however, remain available upon request for three years from the date when they are first posted); and (9) removing § 37.8, because the compliance date for Part 37 has already passed.

In addition, we are requesting that the How Working Group propose changes in the Standards and Protocols document and the Data Dictionary by June 2, 1997 necessitated by the Commission's revised discount policy and by our findings on various requests for rehearing.

We will retain the provisions of Order No. 889 and 18 CFR Part 37 in all other respects. Below, we address the provisions of 18 CFR Part 37 in light of the issues raised in the requests for rehearing.

B. Section 37.1—Applicability

1. Extent of the Commission's Authority to Impose Standards of Conduct

In the OASIS Final Rule, the Commission determined that the rules in Part 37—including the obligation to adopt standards of conduct—would apply to any public utility that owns, operates, or controls facilities used for the transmission of electric energy in interstate commerce. Among other things, we concluded that we would not directly assert jurisdiction over non-public utilities under § 311 of the Federal Power Act (FPA) to ensure compliance with OASIS requirements, including the requirement to comply with the standards of conduct. Instead, we are relying on the reciprocity provision of the Open Access pro forma tariff that requires a non-public utility to offer comparable transmission service to the Transmission Provider as a condition of obtaining open access service.[13]

Rehearing Request

ConEd argues that the Commission lacks authority to issue the standards of conduct requiring functional unbundling.[14] Specifically, ConEd argues that the Commission has exceeded its authority by requiring ''transmission providers to functionally separate interstate electricity transmission and wholesale merchant functions (wholesale sales and purchases of electricity in interstate commerce).''[15] ConEd asserts that wholesale purchases of electricity in interstate commerce on behalf of native load customers are bundled retail electric service transactions that are local distribution and not subject to the Commission's authority.

Commission Conclusion

We agree with ConEd to the extent that when a utility uses its own transmission system to transmit purchased power to retail load customers we have no jurisdiction over the transmission that is included in the bundled sale of power to the retail native load. Upon further consideration, we conclude that our definition of ''wholesale merchant function'' (in § 37.3(e)) should be modified to delete the phrase, ''* * *, or purchase for resale, * * *.'' because this clause creates confusion and is not necessary. When a utility purchases power for its retail native load customers, this is not a sale for resale. In contrast, when a utility purchases power for its wholesale native load, the transmission of purchased power to the wholesale customer is really part of a transaction that includes a wholesale sale of power to a third party. Our authority to require functional unbundling of interstate electricity transmission and the wholesale merchant function, as newly defined, is fully supported in Order No. 888.

2. The Commission's Authority to Impose Reciprocity Provision

In the OASIS Final Rule, we concluded that we will not directly assert jurisdiction over non-public utilities under § 311 of the FPA[16] to ensure compliance with OASIS requirements. We concluded that we would, instead, rely on the reciprocity provision of the Open Access *pro forma* tariff that requires a non-public utility to offer comparable transmission service to the Transmission Provider as a condition of obtaining open access service. We found that if a non-public utility chooses to take open access service, and therefore is subject to the Open Access *pro forma* tariff reciprocity provision, it also is subject to the OASIS and standards of conduct requirements in 18 CFR Part 37, unless the Commission grants a waiver of the reciprocity provision. The reciprocity provision announced in the Open Access Final Rule does not require non-public utilities to provide transmission access, but, instead, conditions the use of public utilities' open access services on an agreement to offer open access services in return.

Rehearing Requests

A number of non-public utilities have raised arguments on rehearing challenging the reciprocity provision. First, some argue that, notwithstanding the Commission's discussion of this issue in Order Nos. 888 and 889, the reciprocity provision is not voluntary.[17] Second, some argue that the Commission lacks the authority to impose the reciprocity provision and that the Commission is trying to accomplish indirectly what it lacks the authority to do directly.[18] Third, CAMU argues that the Commission should defer imposing the reciprocity provision until such time as the IRS clarifies the status of private use limitations within the context of transmission access.[19] NE Public Power District objects that Order No. 889 contained scant discussion of the Commission's authority to impose functional unbundling and other requirements based on the reciprocity provision.[20]

[13] We discuss below, in the next section of this order, issues raised on rehearing that implicate the Commission's authority to condition the use of public utility Open Access *pro forma* tariffs on the provision of reciprocal transmission services, including compliance with the standards of conduct and OASIS requirements.

[14] ConEd Rehearing Request at pp. 2–6.

[15] ConEd Rehearing Request at p. 2.

[16] 16 U.S.C. § 825j.

[17] *See* Requests for Rehearing of AL EC, NE Public Power District, NRECA, and TDU Systems.

[18] *See* Requests for Rehearing of Redding, NE Public Power District, NRECA, and TDU Systems.

[19] CAMU Rehearing Request at pp. 3–4.

[20] This issue was fully considered and addressed in Order No. 888. NE Public Power District also raises a related issue, now moot, concerning possible conflicts between the standards of conduct and state freedom of information laws. Given that this issue concerns the confidentiality provisions of

Continued

Other entities seeking rehearing argue that the Commission did not go far enough in adopting and relying upon the reciprocity provision for purposes of attaining compliance with the OASIS and standards of conduct requirements. CCEM argues that the Commission erred by failing to require nonjurisdictional entities providing reciprocal service to comply with the OASIS requirements. [21]

EEI argues that the reciprocity provision requires all non-public utilities to functionally unbundle their transmission systems, establish an OASIS, and fully comply with the OASIS standards of conduct. Additionally, EEI advances a number of proposals that would expand the reciprocity provision contained in the Open Access Final Rule.[22]

Montana-Dakota argues that the reciprocity provision should be expanded for non-public utilities. It argues that cooperatives should not be able to construct barriers minimizing their obligations under the reciprocity provision.[23]

Commission Conclusion

After consideration of the arguments made on rehearing, both in this rulemaking proceeding and on rehearing of the Open Access Final Rule, we continue to believe that it is appropriate to condition the use of public utility open access tariffs on the agreement of the tariff user to provide reciprocal access to the Transmission Provider. Any eligible customer, including a non-public utility, that takes advantage of open access transmission tariff services should not be allowed to deny service or otherwise discriminate against the open access provider. Moreover, we continue to believe that, absent a waiver, the obligation to provide reciprocal, non-discriminatory services necessarily commits the customer of open access service, even if not a public utility, to abide by the OASIS and standards of conduct requirements.

Contrary to arguments raised on rehearing, we are not *requiring* non-public utilities to provide transmission access. Instead, we are 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. It would not be in the public interest to allow a non-public utility to take non-discriminatory transmission service from a public utility at the same time that it refuses to provide comparable service to the public utility. Such a disparity would restrict the operation of robust competitive markets and would harm the very ratepayers that Congress has charged us to protect.

Similarly, it would not serve the public interest to compel public utilities to have OASIS nodes and to functionally unbundle their wholesale merchant functions from their transmission operations and reliability functions, while allowing non-public utilities that seek open access transmission from a public utility to evade these responsibilities. [24]

Moreover, we have provided a mechanism, equally applicable both to small public utilities and to small non-public utilities, for them to obtain waivers of the OASIS and separation of function requirements and the other reciprocity requirements.[25]

Turning to arguments that assert that the reciprocity condition does not go far enough, we are unpersuaded that we should further expand the reciprocity condition. In our view, the reciprocity condition, as written, suffices to ensure comparability and to avoid undue discrimination. We discuss this matter more fully in Order No. 888–A.

3. Waiver Policy

The Open Access Final Rule provides that public utilities may seek waivers for some or all of the requirements of the Open Access Final Rule, including waiver of the standards of conduct and OASIS requirements. Similarly, the Open Access Final Rule provides that non-public utilities may seek waivers of the tariff reciprocity provision as applied to them.

Rehearing Requests

APPA argues that the Commission should revise the waiver standard for non-public utilities (the reciprocity provision) to allow waivers when a non-public utility lacks market power or where the cost of compliance exceeds the annual net revenues expected to be received from transmission and ancillary services under a reciprocity tariff. APPA further argues that, in such circumstances, compliance with the requirements of the Open Access and OASIS Final Rules would be anti-competitive.[26] Similarly, CAMU argues that only dominant utilities are capable of subverting the transmission market and that, therefore, only such larger utilities should be burdened with the costs of compliance.[27]

Blue Ridge argues that the Commission should clarify that a waiver from compliance with the requirements of Order No. 888 also gives a waiver from compliance with the requirements of Order No. 889.[28]

Indianapolis P&L argues that the Commission's criteria for evaluating waiver requests are too rigid and that it probably will be denied waiver even though it is a small system that lacks transmission market power.[29]

Michigan Systems argue that small systems that lack market power in transmission should be granted a blanket exemption from compliance with the separation of functions requirement in the OASIS standards of conduct, without the necessity for applying for waivers on a case-by-case basis.[30]

Ohio Valley argues that the criteria in the Open Access Final Rule for obtaining waivers from compliance with Order Nos. 888 and 889 are too stringent and should be revised to accommodate waivers whenever justified. [31] It argues that control area operators should not be excluded from obtaining a waiver of the Commission's Open Access requirements. Ohio Valley adds that the waiver process is uncertain and that its 1953 agreement to supply power to the United States Department of Energy should be ''grandfathered'' and exempted from compliance with the requirements of Order Nos. 888 and 889.

TAPS argues that in areas of the country where a major transmission owner elects to set up its own OASIS, in lieu of participation in a regional OASIS, or refuses to allow smaller utilities to participate in an OASIS, waivers should be granted to the smaller utilities so that they are not forced to set up their own OASIS sites, the costs of which would be unwarranted. TAPS further argues that larger utilities that do

§ 37.6(e), we will address this issue below in section IV.G.8 of this order.

[21] CCEM Rehearing Request at p. 10.

[22] EEI Rehearing Request at n.10 and pp. 2, 7–15.

[23] Montana-Dakota Rehearing Request at pp. 2–4.

[24] See South Carolina Public Service Authority (*Santee Cooper*), 75 FERC ¶ 61,209 (1996); Central Electric Cooperative, Inc., 77 FERC ¶ 61,076 (1996).

[25] Moreover, as we discuss further below, *see supra* sections IV.B.3 and V., the Commission has granted waivers to a number of small non-public utilities from the requirements to establish and maintain an OASIS and the requirement in the standards of conduct to separate the wholesale merchant function from the transmission operation and reliability function.

[26] APPA Rehearing Request at pp. 9–11.

[27] CAMU Rehearing Request at pp. 2–3.

[28] Blue Ridge Rehearing Request at p. 39. We note that the Commission only granted waiver of Order No. 889 requirements to those public utilities that made a specific request for waiver of those requirements. *See infra* n.33, First Waiver Order, 76 FERC at 62,296–97.

[29] Indianapolis P&L's request for waiver was denied in the First Waiver Order, *infra* n.33, *see* 76 FERC at 62,295. Indianapolis P&L's request for rehearing in Docket No. OA96–81–001 currently is pending.

[30] Michigan Systems Rehearing Request passim.

[31] Ohio Valley Rehearing Request at p. 12.

not allow smaller utilities to participate with them in a joint OASIS should not be able to deny service to those smaller utilities on that basis.[32]

Commission Conclusion

Since issuance of the Open Access and OASIS Final Rules, the Commission has issued a series of orders addressing specific requests for waiver of all or some of the requirements of the Open Access and OASIS Final Rules, including the requirements under Order No. 889 to: (1) establish and maintain an OASIS; and (2) comply with the standards of conduct (including the requirement to separate the activities of, and restrict communications between, employees performing wholesale merchant functions and employees performing system operations and reliability functions).[33] The waiver standards enunciated by the Commission apply to public utilities subject to the rules, as well as to non-public utilities that seek waiver of the reciprocity provision.

In *Black Creek,* the Commission announced modified standards used to determine whether to grant waiver of Order Nos. 888 and 889.[34] Under these modified standards, waiver of Order No. 889 would be appropriate: (1) if the applicant owns, operates, or controls only limited and discrete transmission facilities (rather than an integrated transmission grid); or (2) if the applicant is a small public utility[35] that owns, operates, or controls an integrated transmission grid. With respect to the second category, a waiver would not be available if the utility is a member of a tight power pool, or other circumstances are present which indicate that a waiver would not be justified.[36] The Commission, in addressing situations where waiver is granted, further stated that:

> Waiver of the requirement to establish and maintain an information system (*i.e.,* an OASIS) will be granted unless and until an entity evaluating its transmission needs complains that it could not get information necessary to complete its evaluation. Waiver of the standards of conduct will be granted unless and until an entity complains that a public utility has used its access to information about transmission to unfairly benefit the public utility's own or the public utility's affiliates' sales. Compliance must be made within 60 days of the complaint.[37]

Thus, the Commission has developed waiver criteria that take into account potential burdens on small entities and at the same time balance the need to prevent undue discrimination and affiliate abuse in interstate power markets. We believe that this flexible waiver approach adequately addresses the concerns raised on rehearing.

In response to the requests for rehearing of Indianapolis P&L and Ohio Valley, this order on rehearing is not the proper vehicle for a company to request a company-specific waiver. Waivers are appropriately addressed on a case-by-case basis, which permits the Commission to review the specific facts of each waiver application and permits affected parties to intervene and make their views known to the Commission.[38]

TAPS expresses a concern that larger utilities may not allow smaller utilities to participate with them in a joint OASIS. We do not believe that any revisions to the OASIS Final Rule are necessary at this time to address TAPS' concern, because: (1) if the OASIS for its particular geographic area is unavailable, a utility may always choose to participate in an OASIS for a different region;[39] (2) smaller utilities should be able to meet their OASIS obligations cost-effectively by joining with other small entities to hire the services of private vendors collectively; and (3) as mentioned above, the Commission will grant waivers of the OASIS requirements to small utilities under proper circumstances.

Moreover, we do not currently have any evidence that larger utilities will, in fact, attempt to exclude smaller utilities from participating in their OASIS sites. In fact, all indications are to the contrary.

Thus, while we are not taking any steps based on TAPS' concerns, at this time, we will revisit this issue if it appears that Commission action is appropriate. We would also entertain a company-specific complaint that a larger utility is misusing the reciprocity provision to improperly withhold transmission service.

C. Section 37.2—Purpose

The requests for rehearing did not specifically address this provision nor seek revision of this portion of the OASIS Final Rule.

D. Section 37.3—Definitions

The OASIS Final Rule contains definitions of ''Transmission Provider'', ''Transmission Customer'', ''Responsible Party'', ''Reseller'', ''Wholesale Merchant Function'', and ''Affiliate''.[40] The requests for rehearing did not specifically address these definitions nor seek revision of this portion of the OASIS Final Rule. However, as discussed above, we are modifying the definition of ''wholesale merchant function'' in response to ConEd's request for rehearing or clarification.

E. Section 37.4—Standards of Conduct

In the OASIS Final Rule, we adopted standards of conduct intended to accomplish four main objectives. First, we prohibited Transmission Providers from giving preferential access to information related to transmission prices and availability to employees of the public utility, or any affiliate, engaged in wholesale merchant functions. We accomplished this by: (a) Requiring that transmission-related information be made available to all customers (including employees of the public utility, and any affiliate, engaged in wholesale merchant functions) through OASIS postings available at the same time and on an equal basis; and (b)

[32] *See* related issue, discussed in section IV.F below, concerning the argument that Transmission Providers must create regional OASIS nodes.

[33] *See, e.g.,* Northern States Power Company (MI), *et al.*, Order on Requests by Public Utilities for Waivers of Order No. 888 and 889, 76 FERC ¶ 61,250 (1996) (*First Waiver Order*); *order on reh'g,* Black Creek Hydro, Inc., *et al.*, Order on Rehearing and Granting Waivers of Order No. 889, 77 FERC ¶ 61,232 (1996) (*Black Creek*); Midwest Energy, Inc., *et al.*, 77 FERC ¶ 61,208 (1996) (*Midwest*); Soyland Power Cooperative Association, *et al.*, 78 FERC ¶ 61,095 (1997) (*Soyland*); Dakota Electric Ass'n, *et al.*, 78 FERC] 61,117 (1997) (*Dakota*). In addition, the Commission, in Central Electric Cooperative, Inc., *et al.*, 77 FERC ¶ 61,076 (1996), *reh'g pending* (*Central Electric*); *Dakota;* and Niobrara Valley Electric Membership Corporation, Docket Nos. OA96–146–001 and ER97–1412–000 (*Niobrara*), addressed various requests for rulings on exemptions from and waivers of Order Nos. 888 and 889, on the basis that applicants are not public utilities subject to the requirements of the Final Rules.

[34] To avoid confusion, we will discuss the waiver standards as set out in *Black Creek* rather than in the First Waiver Order, because *Black Creek* modified the First Waiver Order's standards for waiver.

[35] To qualify as a small public utility, the applicant must meet the Small Business Administration definition of a small electric utility, *i.e.*, one that is independently owned and disposes of no more than 4 million MWh annually.

[36] *Black Creek,* 77 FERC at 61,941; *see also Midwest,* 77 FERC at 61,854 (elaborating on the exception where the applicant is a member of a tight power pool).

[37] *Black Creek,* 77 FERC at 61,941 (citation to First Waiver Order omitted).

[38] As noted above, *supra* n.29, Indianapolis P&L's specific waiver request was addressed in the First Waiver Order and is pending rehearing. To date, Ohio Valley has not filed a specific request for waiver.

[39] We note that even though a majority of the OASIS nodes are joint nodes, these nodes nevertheless report data on a company-specific basis that is accessed using each company's individual Internet World Wide Web (WWW) address. Thus, the geographic location of the Transmission Provider is irrelevant to locating data about that company's operations on the Internet.

[40] Additionally, § 37.6(b)(1) provides definitions of ''Posted Path'', ''Constrained Posted Path'', and ''Unconstrained Posted Path'' as used in § 37.6. As these additional terms were defined in § 37.6 of the OASIS Final Rule, we will discuss suggestions to clarify these terms in sections IV.G.1 and IV.G.2 below.

prohibiting the employees of Transmission Providers and any affiliates from disclosing or obtaining non-public transmission-related information through communications not posted on the OASIS. Thus, employees engaged in wholesale merchant functions may only obtain information about transmission prices and availability from postings on the OASIS or from public sources equally available to all other customers.

Second, we mandated that employees engaged in system operations and reliability functions must treat all customers in a fair and impartial manner and may not give any preferential treatment to the company's (or its affiliates') employees conducting wholesale merchant functions. This requirement includes not disclosing market information about a customer and its activities to other customers in the course of responding to requests for transmission service.

Third, we required the functional unbundling of the transmission operations and wholesale merchant functions of public utilities and their affiliates so that those employees charged with system operations and reliability would be free to operate the system impartially for the benefit of all customers, including the Transmission Provider itself.[41]

Fourth, to ensure that the OASIS Final Rule would not compromise reliability, we created an exemption, in emergency circumstances affecting system reliability, that allows system operators to take whatever steps are necessary to keep the system in operation.

Finally, we warned that the standards of conduct are to be interpreted consistent with common sense, prudence, and caution, and that the burden is on entities subject to the rules to design procedures and safeguards and to take all necessary actions to ensure compliance. Those who have questions on these issues may contact the Enforcement Task Force Hotline at 202–208–1390 to obtain informal advice on implementing the standards of conduct.

[41] As explained in the OASIS Final Rule, functional unbundling seeks to ensure that the same employee is not responsible for performing both wholesale merchant functions and system operation functions at the same time. *See* OASIS Final Rule, 61 FR at 21,744–48. These functions are to be performed by separate employees and the standards of conduct provide that they are prohibited from communicating with each other about transmission-related matters unless they do so through the OASIS. *See* §§ 37.4(a) and 37.4(b).

1. Contacts Between Employees Providing Ancillary Services and System Operators

The OASIS Final Rule defines the ''wholesale merchant function'' at § 37.3(e). The definition contains no specific reference to, or exclusion of, ancillary services. In the Open Access Final Rule, the Commission concluded that six ancillary services must be included in an open access transmission tariff.[42]

Rehearing Request

Allegheny argues that an employee of the Transmission Provider who is responsible for providing customers with ancillary services mandated by the Open Access Final Rule should not, for that reason, be deemed to be a ''merchant employee'' excluded from contact with system operators under Order No. 889.[43]

Commission Conclusion

We disagree with Allegheny's interpretation of the OASIS standards of conduct. Under the standards of conduct, employees who are responsible for providing ancillary services are not (without regard to their actual job functions) uniformly deemed to be, or not to be, wholesale merchant employees. To the contrary, whether these employees are deemed to be wholesale merchant employees, or not, depends on the nature of their job functions.

The Transmission Provider's sale of ancillary services in support of its provision of basic transmission service is not a wholesale power merchant function for purposes of Order No. 889. This is because the provision of ancillary services is essential for providing basic transmission service. However, the sale of ancillary service not in support of the Transmission Provider's provision of basic transmission service is a wholesale merchant function for purposes of Order No. 889. Thus, if an employee is marketing an ancillary service independent of the Transmission Provider's obligations to provide basic transmission service, then that employee would be providing a wholesale merchant function and would be subject to the applicable requirements pertaining to wholesale merchant employees under the standards of conduct.

[42] These are: (1) Scheduling, system control and dispatch service; (2) reactive supply and voltage control from generation sources service; (3) regulation and frequency response service; (4) energy imbalance service; (5) operating reserve—spinning reserve service; and (6) operating reserve—supplemental reserve service.

In the Open Access Final Rule, the Commission has determined that the Transmission Provider must provide and the Transmission Customer must purchase from the Transmission Provider the first two services listed above, subject to conditions set out in Order No. 888. The Transmission Provider must offer the remaining four services to the Transmission Customers upon request.

[43] Allegheny Rehearing Request at pp. 9–10.

Therefore, we reject Allegheny's suggestion that our current regulations *categorically* deem *any* employees involved in the provision of ancillary services as not being wholesale merchant employees, without regard to their actual job responsibilities.

2. Contacts Between Generation Control Employees and Transmission Operations and Wholesale Merchant Employees

Among other matters, the OASIS standards of conduct preclude employees engaged in wholesale merchant functions from improperly communicating with employees engaged in transmission system operations or reliability functions. However, we did not extend Order No. 888 or the OASIS Final Rule to require the corporate unbundling of transmission and generation control functions or to mandate the divestiture by Transmission Providers of their generation assets.

Rehearing Request

CCEM argues that the Commission erred by not drafting the standards of conduct to preclude generation control employees from being a conduit for improper communications between transmission operations personnel and wholesale merchant personnel.[44]

Commission Conclusion

As we stated above, in our discussion of whether employees responsible for providing ancillary services are to be deemed wholesale merchant employees, what limitations are placed on an employee's conduct under the standards of conduct depends on that employee's actual job functions and activities, rather than that employee's job title.[45] In the same way, whom a generation control employee may or may not communicate with depends on the respective job functions of that generation control employee and the employee(s) with whom he or she intends to communicate. Generation control employees whose job responsibilities involve wholesale merchant functions would be precluded from having pertinent off-the-OASIS communications with employees

[44] CCEM Rehearing Request at pp. 10–11.

[45] *See supra* discussion in section IV.E.1 above.

performing system operations and reliability functions.

Additionally, notwithstanding CCEM's concerns, the standards of conduct *already* preclude *any* employee from acting as a conduit for improper communications between transmission operations employees and wholesale merchant employees. Furthermore, if these activities were carried out by a non-employee (*e.g.,* an outside attorney or consultant), they nevertheless would constitute a violation of the standards of conduct by the involved transmission operations employee(s), the involved wholesale merchant employee(s), and their employer. This being the case, we reject CCEM's proposal as unnecessary.

3. Monitoring the Standards of Conduct

The preamble's discussion of the standards of conduct and the regulations at § 37.4 are intentionally directed at the responsibilities of the Transmission Providers subject to these rules rather than the Commission's plans to monitor compliance and pursue enforcement strategies.

Rehearing Requests

APPA and Blue Ridge argue that monitoring of the standards of conduct is essential and that the Commission must establish and publicize a plan to do so.[46] APPA argues that reliance on utility self monitoring is not sufficient.

Commission Conclusion

We agree with APPA and Blue Ridge that it is important for the Commission to monitor compliance with the standards of conduct carefully and that self monitoring may not be fully sufficient to accomplish this. Accordingly, we are amending §§ 37.4(b)(5)(iii) and 37.6(g)(4) to require the posting on the OASIS of information from a Transmission Provider that details the circumstances when it exercises its discretion in applying any terms of the tariff (and which Transmission Providers already are required to maintain pursuant to § 37.4(b)(5)(iii)). This will assist the Commission in monitoring whether the standards of conduct are being met. Consistent with § 37.7(b), which governs the retention period for audit data, this information must remain available for download on the OASIS for a specified period, and must remain available upon request for three years from the date when such information is first posted.[47] We request that the How Working Group propose the necessary template to be included in the Standards and Protocols document.

As to APPA's and Blue Ridge's specific suggestions that we should modify the OASIS Final Rule to address the Commission's oversight plans and functions, we do not believe that this would be appropriate. Although the Commission is well aware of the importance of its enforcement responsibilities, and will remain vigilant in reviewing the operation of OASIS sites and compliance with the standards of conduct, the purpose of the OASIS Final Rule is to detail the responsibilities of the regulated community and not those of the Commission.

4. Adequacy of Emergency Exception

As explained above, the OASIS standards of conduct include an exception, in emergency circumstances affecting system reliability, that allows system operators to take whatever steps are necessary to keep the system in operation.

Rehearing Request

El Paso argues that the standards of conduct's emergency exception is inadequate; contingencies may arise daily that require a system operator to react promptly to unanticipated losses of generation units. Therefore, operators should be allowed to buy and sell current hour and next hour power (to preserve system reliability). El Paso does not oppose the separation of functions as applied to longer-term transactions (*i.e.,* transactions involving transmission service beyond the current hour and next hour).[48]

Commission Conclusion

We reject the proposal to allow operators to buy for resale at wholesale and sell at wholesale next hour power on a routine basis, without regard for the separation of functions required by the standards of conduct. We find this proposal too broad and find that it has too much potential for abuse. However, as explained more fully below, the regulations do not dictate what group of employees is to have responsibility for making purchases on behalf of bundled retail customers. For example, the transmission operations and reliability function may be assigned responsibility for making purchases on behalf of bundled retail customers.

5. Short-Term Economy Energy Purchases

FIT Utilities do not object generally to functional unbundling; however, they argue that the system operator should be allowed to make short-term economy energy purchases in order to maintain system reliability.[49] FIT Utilities further argue that, while the OASIS Final Rule does not require the physical separation of transmission and generation dispatchers, it does effectively rewrite generation dispatchers' jobs to exclude the purchase for resale and sale at wholesale of energy in hourly interchange markets. FIT Utilities argue that a generation dispatcher needs to know loads on transmission lines on an instantaneous basis to assess whether to increase or decrease outputs from particular generation facilities. FIT Utilities argue that generators are often run, not for energy, but for voltage support or to otherwise stabilize the transmission system.

They argue that, in addition to reliability concerns, system operators also worry about keeping transactions economical. They argue that separating the functions relating to short-term energy purchases (for resale) makes this task harder, at a substantial cost to consumers. They continue that allowing a dispatcher to *buy* power would not hurt competition, as long as the dispatcher cannot also *sell* power.[50] They add that if a dispatcher buys power that offsets higher cost utility generated power, this helps everyone.

For these reasons, FIT Utilities argue that the OASIS Final Rule should be revised to retain a prohibition against a dispatcher selling power while allowing the dispatcher to buy power. FIT Utilities argue that, at a minimum, the dispatcher should be able to buy power in hourly economic energy markets to serve load.[51] They argue that if the Commission has a concern that this would somehow be anti-competitive, then a utility should be allowed to set up a computer system to make such purchases automatically. They argue that the Commission should be concerned with both reliability and price and should aim for the lowest cost supply possible.

Commission Conclusion

The standards of conduct's separation of functions currently prohibit a Transmission Provider's employees engaged in transmission system operations and reliability functions from giving preference to wholesale

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[46] APPA Rehearing Request at pp. 11–19, Blue Ridge Rehearing Request at p. 39.

[47] Under § 37.7(b), all audit data currently must remain available for download for 90 days. Later in this order, we shorten the retention period for making ATC/TTC postings available for download to 20 days, with the data to be made available upon request for three years. *See* discussion in section IV.H below.

[48] El Paso Rehearing Request at pp. 1–4.

[49] FIT Utilities Rehearing Request at pp. 39–40.

[50] FIT Utilities Rehearing Request at p. 42.

[51] FIT Utilities Rehearing Request at p. 43.

purchases or sales made on behalf of its own wholesale customers or those of affiliates. The standards of conduct do not, however, dictate whether bundled retail merchant functions are to be grouped with the wholesale merchant function or with the transmission operations and reliability function.

Thus, FIT Utilities' request to allow dispatchers to buy power to serve retail load is consistent with the regulations. As discussed above, the regulations do not prohibit Transmission Providers from assigning the responsibility for making purchases to serve bundled retail customers to the transmission operations and reliability function.

To avoid any confusion, we are modifying § 37.4(b)(5)(iv) to substitute the phrase ''sales for resale made by the wholesale merchant function or any affiliate'' for the phrase ''wholesale purchases or sales made on behalf of its own power customers, or those of an affiliate'' in § 37.4(b)(5)(iv).

Moreover, nothing in the standards of conduct prohibits a public utility subject to the rule from arranging to have the same data about the company's generation sources and load simultaneously fed to both transmission system operators and merchant employees. Thus, if the company elects to have wholesale merchant employees perform the function of making purchases to serve bundled retail native load, this can be done without necessitating any change in the standards of conduct. Data received by system operators about the activities of third parties may not be conveyed to wholesale merchant employees except through postings on the OASIS equally available to all OASIS users.

6. Tight Pools

NY MU argues that the Commission erred in not requiring operational unbundling, at least for tight pools, which NY MU asserts includes requiring that the transmission component of retail rates be treated as if the rates were based on the use of the pool-wide *pro forma* tariff of the Open Access Final Rule.[52]

Commission Conclusion

As further discussed in Order No. 888–A,[53] the Commission stands by its decision in the Open Access Final Rule that functional unbundling, along with the flexible safeguards contained in the Final Rule, is a reasonable and workable means of assuring non-discriminatory open access transmission. The Commission has not found it necessary to adopt a more intrusive and potentially more costly approach at this time based on speculative allegations that functional unbundling may not work and that more severe measures may be needed.

7. Clarification of § 37.4(b)(5)(iv)

As modified above, § 37.4(b)(5)(iv) requires that a Transmission Provider not, through its tariffs or otherwise, give preference to sales made to any person for resale made by the wholesale merchant function or by any affiliate, over the interests of any other wholesale customer in matters relating to the sale of wholesale transmission service.

Rehearing Request

SoCal Edison asks the Commission to clarify that the OASIS rule (§ 37.4(b)(5)(iv)) was not intended to require the Transmission Provider or network customer to charge itself for transmission for its economy energy purchases or to assign to those purchases the same curtailment priority assigned to other non-network, non-firm point-to-point transactions. [54]

Commission Conclusion

Turning first to the narrow issue raised by SoCal Edison's request for rehearing, we clarify that § 37.4(b)(5)(iv) was intended to be consistent with the Open Access *pro forma* tariff provisions of Order No. 888. Moreover, we intended that the question raised by SoCal Edison would be answered by reference to the provisions of the Open Access *pro forma* tariff. Thus, § 37.4(b)(5)(iv) does not require the Transmission Provider or network customer to charge itself for transmission for its economy energy purchases. Nor does it require that they assign to those purchases the same curtailment priority assigned to other non-network, non-firm point-to-point transactions. Under the Open Access *pro forma* tariff, if purchases are for bundled retail sales, then the Transmission Provider is not required to charge itself for its economy energy purchases. By contrast, if the purchases are for wholesale sales, then the Transmission Provider must charge itself for the transmission. The same delineation would also apply to curtailment priority.

Moreover, we clarify that § 37.4(b)(5)(iv) was not intended to rewrite the rules regarding utilities' purchases and priorities for bundled retail customers, nor to set aside the rules prescribed in section 1.11 of the Open Access *pro forma* tariff.[55]

8. Discounts

The issue of what discounts must be provided by a Transmission Provider who offers a discount to its affiliates or its own wholesale merchant function was addressed in the Open Access Final Rule. The matter also was discussed in the OASIS Final Rule, but only to the extent that it related to what information must be posted on the OASIS.[56] In § 37.4(b)(5)(v), we mandated that when a Transmission Provider offers a discount to its wholesale merchant function or any affiliate, then it must, at the same time, post on the OASIS an offer to provide the same discount to all Transmission Customers on the same path and on all unconstrained transmission paths.[57] The posting requirement corresponding to this obligation to offer discounts was contained in § 37.6(c)(3). We also found, in § 37.6(c)(3), that discounts offered to non-affiliates must be posted within 24 hours of when available transmission capability (ATC) is adjusted in response to the transaction.

The requests for rehearing address both: (1) what discounts must be offered; and (2) what postings must accompany discount offers. As

[52] NY MU Rehearing Request at pp. 5, 7. *See* Open Access *pro forma* tariff at p. 5.

[53] *See* Order No. 888–A at section IV.A.

[54] SoCal Edison Rehearing Request at p. 24. On July 18, 1996, SoCalGas filed a request for clarification responsive to SoCal Edison's rehearing request, which argues that § 37.4(b)(5)(iv), together with the Open Access Final Rule, provide for comparability and that: ''a Transmission Provider is not entitled to accord itself special priority, special services, or special prices, *merely* because it owns the transmission facilities, and the Transmission Provider is not permitted to import wholesale power 'for free'; however, the Transmission Provider may enjoy any priorities or advantages provided to it and similarly situated customers by the express terms of its transmission tariff.''

SoCalGas' arguments overlook that SoCal Edison itself concedes that if § 37.4(b)(5)(iv) is interpreted in harmony with Commission precedent, it would: ''operate to ensure that the Transmission Provider would not give preference to its own purchases and sales over that of other similarly situated customers (*e.g.*, by assigning a higher curtailment priority to its own economy energy purchases than it would assign to an identical economy energy purchase by a network customer).'' Thus, the issues raised in SoCalGas' request for clarification are not before us.

[55] Section 1.11 of the Open Access *pro forma* tariff is also the subject of a number of requests for rehearing that are addressed in Order No. 888–A at section IV.C.1.

[56] In Order No. 889, we found that if a Transmission Provider offers a discount to an affiliate, or attributes a discounted transmission service rate to its own wholesale transactions, then the Transmission Provider must, at the same time, post on the OASIS an offer to provide the same discount to all eligible customers. If a Transmission Provider offers discounts to non-affiliates, it must offer to do so on a basis that is not unduly discriminatory.

[57] In Order No. 888–A, we are addressing arguments that we should revise the requirement to offer the same discount to all Transmission Customers on the same path and on all unconstrained transmission paths.

explained in Order No. 888–A, we have decided to revise our policy on discounts of transmission services, and to apply this same policy, with the exception concerning paths, to ancillary services provided by the Transmission Provider in support of its provision of basic transmission service. To implement this revised policy, we are making changes to the standards of conduct and to the posting of discounts under § 37.6. We address changes to the standards of conduct here, and changes to § 37.6 in section IV.G.6 below.

Under our revised discount policy, three principal requirements are appropriate. First, any offer of a discount for transmission and/or ancillary services made by the Transmission Provider must be announced to all potential customers solely by posting on the OASIS. This requirement, which will ensure that all potential Transmission Customers under the Open Access *pro forma* tariff will have equal access to discount information, will guard against the Transmission Provider's wholesale merchant function or an affiliate gaining an unfair timing advantage concerning the availability of discounts.

Second, we will require that any customer-initiated requests for discounts of transmission and/or ancillary services occur solely by posting on the OASIS, regardless of whether the customer is the Transmission Provider's wholesale merchant function, an affiliate, or a non-affiliate. We will permit customer-initiated requests for discounts but will require that such requests be visible (via posting on the OASIS) to all market participants.

Third, we will require that, once the Transmission Provider and customer agree to a discounted transaction for transmission and/or ancillary services, the details be immediately posted on the OASIS. This requirement will be equally applicable regardless of whether the customer is the Transmission Provider's wholesale merchant function, an affiliate, or a non-affiliate.

Additionally, we believe that any ''negotiation'' between a Transmission Provider and a potential customer should take place on the OASIS, and should be visible to all market participants, and we will revise our regulations to accomplish this as soon as practicable. To this end, we direct the How Working Group, by no later than June 2, 1997, to propose: (1) Whatever changes are needed to the Standards and Protocols document; and (2) the earliest date when the industry can meet such a requirement during Phase I.

In §§ 37.4(b)(5)(v) and 37.4(b)(5)(vi), we required Transmission Providers to post on the OASIS any offers they made to their wholesale merchant function or to their affiliates of a discounted price for transmission services or ancillary services. We are now deleting these provisions because under our revised discount policy, the distinction between discounts to affiliates and discounts to non-affiliates has been abandoned.

As discussed above, we are addressing the modifications to the posting requirements in § 37.6 in Section IV.G.6 below.

F. Section 37.5—Obligations of Transmission Providers and Responsible Parties

In the OASIS regulations, the Commission requires Transmission Providers to operate an OASIS, either individually or jointly with other Transmission Providers. The Transmission Provider may delegate this responsibility to a Responsible Party such as another Transmission Provider, an Independent System Operator, a Regional Transmission Group, a Regional Reliability Council, or a third-party operator. Nevertheless, each Transmission Provider remains responsible for compliance, regardless of whether it establishes its own OASIS or participates in a joint OASIS.

Rehearing Requests

TAPS and TDU Systems argue that the Commission should require Transmission Providers to establish a regional OASIS because individual utility OASIS sites are inefficient. They contend that, as the number of OASIS sites increases, OASIS postings become less meaningful and the accomplishments of the OASIS Final Rule lessen.[58]

Commission Conclusion

At this juncture, the Commission continues to believe it appropriate to encourage, but not require, regional OASIS sites. It is the Commission's understanding that most utilities are participating in regional OASIS sites. This issue can be revisited in Phase II of OASIS, if a significant number of utilities fail to join a regional OASIS and this results in significant inefficiency in bulk power markets.

G. Section 37.6—Information to be Posted on an Oasis

1. Definition of ''Posted Path''

Section 37.6(b)(1)(i) defines a posted path as: (1) any control area to control area interconnection; (2) any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and (3) any path for which a customer requests the posting of ATC or total transmission capability (TTC). For posted paths requested by customers, the paths must be posted for 180 days and the posting must continue after that until 180 days elapse from the most recent request for service over the path.

Rehearing Requests

CCEM argues that the Commission erred by requiring posting of ATC solely at interfaces between control areas. CCEM further argues that the Commission should require the posting of paths across control areas.[59]

MAPP argues that the Commission should reconsider the requirement to post ATC between control areas or, in the alternative, should grant it a waiver of this requirement. MAPP suggests that posted paths should be defined as paths between zones determined by transmission constraints. MAPP argues that defining posted paths in this manner would be more consistent with the MAPP regional flow-based transmission arrangement.[60]

EEI asks the Commission to revise the criteria for a customer-requested posted path. EEI argues that customers should have to make a service request over the path within 180 days of asking that the path be a posted path or face a penalty.[61]

Commission Conclusion

The Commission will not require the posting of all paths across control areas, since customers can request to have ATC and TTC posted for any path. Given that customers can request to have ATC and TTC posted for any path, adopting CCEM's proposal would burden OASIS sites with a very large number of posted paths that may have little commercial value.

As to MAPP's request to drop the requirement for posting ATC for paths between control areas, MAPP's concern appears to relate to business relationships particular to the MAPP agreement. MAPP's request for a waiver is not based on a lack of traffic over its system. It is based on the fact that MAPP's control areas do not correspond to the service territories of its members (MAPP has 26 utilities and 14 control areas). Some of its control areas cover the generation of more than one utility. Other control areas overlap the same

[58] TAPS Rehearing Request at pp. 8–9 and TDU Systems Rehearing Request at p. 85.

[59] /CCEM Rehearing Request at pp. 7–8.

[60] /MAPP Rehearing Request at pp. 4–10.

[61] /EEI Rehearing Request at p. 53.

geographic area, with each control area covering the generation of a separate utility.

Under MAPP's proposal, it will provide pool-wide transmission service based on a MW mile methodology. It proposes to determine the transmission availability for known constrained interfaces or paths and assess the impact on its member systems of each transaction based on the POD and POR for each transaction. MAPP argues that the Open Access Final Rule was intended to accommodate flow based pricing methods and that, under the circumstances, it makes sense for its member systems to make postings for area to area interfaces rather than control area to control area interfaces. MAPP argues that we should either change our rules for posting between control areas or grant it a waiver.

After reviewing MAPP's arguments, we do not believe that it would be appropriate to modify the ATC posting requirements to address a MAPP-specific issue. However, the Commission will grant MAPP a limited waiver of the control area to control area ATC/TTC posting requirement (in § 37.6(b)(1)(i)) based on the particular circumstances presented by the MAPP system. This waiver should not harm Transmission Customers because MAPP provides pool wide transmission service using a flow based (single MW-mile) pricing methodology for the entire system and proposes to determine transmission availability for all known constrained interfaces or paths. Moreover, this waiver only applies to postings for intra-MAPP interfaces. MAPP will still be required to post ATC and TTC for control area to control area paths that connect its member systems with neighboring transmission systems. Finally, MAPP customers can always request that ATC/TTC be posted for a specific path including a control area to control area path (in which case MAPP would be required to post the information for the path on its OASIS node).

Turning to EEI's suggested limitations on customers requesting that paths be posted, we find that requiring a customer to request service over any path that it asks to be posted places too heavy a burden on customers. However, the Commission may reconsider this requirement if we find that customers abuse the system by requesting postings for too many paths over which no requests for service are made.

2. Definition of ''interconnection''

''Posted path'' is defined in § 37.6, in part, as ''any control area to control area interconnection.'' However, the regulation does not provide a definition of ''interconnection''.

Rehearing Request

EEI and Public Service Co of CO ask the Commission to clarify that the term ''interconnection'', in the definition of ''posted path'' in § 37.6, includes lines connecting two systems or control areas rather than just one line.[62]

Commission Conclusion

To avoid any confusion, we clarify that the term ''interconnection'' in the definition of posted path means all facilities connecting two adjacent control areas and we are amending § 37.6 accordingly. This is consistent with the definition of ''interconnection'' in NERC's Glossary of Terms: ''the facilities that connect two systems or Control Areas.''[63]

3. ATC Supporting Information

The OASIS regulations require that the Responsible Party make all data used to calculate ATC and TTC for any constrained path publicly available within one week of the ATC/TTC posting.

a. Disclosure of Data Supporting Calculations of ATC and TTC

Rehearing Request

EEI argues that the requirement in § 37.6(b)(2)(ii) to disclose data supporting calculations of ATC and TTC provides competitors with backdoor access to sensitive proprietary information. It claims that the Commission intended to allow companies to keep confidential information such as generation run status and the maintenance schedules for generation and transmission.[64]

Commission Conclusion

EEI is correct that the Commission declined in the OASIS Final Rule to require the posting of information about the run status of generation and transmission facilities. However, EEI incorrectly attributes the Commission's decision to a finding on the claimed proprietary nature of this information. The Commission did not require the same-time posting of facility status information because the Commission did not believe this information was needed for Phase I implementation. The OASIS Final Rule states that the Commission may reconsider the issue in Phase II.

On rehearing, EEI argues that the same considerations about commercial sensitivity that led the Commission to decline to order the same-time posting of facility status also dictate that this information should not be divulged as part of the data supporting ATC calculations. We reject this argument for three reasons. First, as shown above, EEI's argument is based on a false premise as to why the Commission declined to order the same-time posting of information on facility run status.

Second, even if, *arguendo,* we accepted EEI's contention that the same-time posting of facility run status is commercially sensitive, this still would not suffice to show that making ATC supporting information available on request and after seven days would have any adverse competitive impact. Whatever commercial sensitivity the information might have would be greatly diminished by the fact that seven days need to elapse before a request for the information can be made. In our view, this delay ensures that no realistic concern remains about the competitive consequences of releasing this information.

Finally, the purpose of ATC supporting information is to ensure that Transmission Customers have confidence in ATC/TTC postings. The OASIS and the Commission's functional unbundling policy depend on customers being able to rely upon the accuracy of ATC postings. The availability of ATC supporting information is essential for building and maintaining this confidence. Thus, the concerns raised by EEI about commercial sensitivity are, in our judgment, outweighed by the public interest served by making this information available, upon request, after seven days. The Commission will not further restrict the availability of information needed to support ATC/TTC calculations and this information will continue to be available to customers upon request after seven days.

b. Disclosure of Data on Nonfirm ATC

Rehearing Request

EEI also argues against disclosing supporting data on nonfirm ATC because it would not exist but for the collection of data to calculate firm ATC and TTC.[65]

Commission Conclusion

If, as EEI claims, data supporting the calculation of nonfirm ATC does not exist in an independent form and is a residual of calculating firm ATC, then

[62] EEI Rehearing Request at p. 48 and Public Service Co of CO Rehearing Request at pp. 1–2.

[63] NERC's Glossary of Terms, August 1996.

[64] EEI Rehearing Request at pp. 49–52.

[65] EEI Rehearing Request at p. 52.

requiring a Transmission Provider to document how it calculates nonfirm ATC should be relatively simple and should not require much additional information. Therefore, the Commission requires that supporting information for firm and nonfirm information be available as required in § 37.6(b)(2)(ii).

c. Time Limits for Disclosure of Utility Generation Data

In the OASIS Final Rule, the Commission rejected arguments by NUCOR that the Commission should require data on generation costs to be posted on OASIS on a same-time basis.[66]

Rehearing Request

On rehearing, NUCOR argues again that the Commission should require same-time disclosure of utility generation data used for economic dispatch.[67]

Commission Conclusion

In the OASIS Final Rule, we rejected the argument that we should require the same-time disclosure of utility generation data used for economic dispatch based on a balancing of the need for the information, the claimed commercial sensitivity of the information, and the desire to avoid, to the extent possible, having public utilities reporting generation data that their competitors may not be required to report. We concluded that the information was not necessary and that during Phase I we would limit OASIS postings to essentials.

On rehearing, NUCOR attempts to buttress its argument by pointing out that utilities will face financial pressure to maintain or enhance their market share in electric generation and that the Commission's enforcement of the standards of conduct could be enhanced by requiring the same-time disclosure of generation data. NUCOR expresses the concern that after-the-fact complaints, unearthed based on a review of audit files, may be neither feasible nor practical.

NUCOR's arguments about discriminatory treatment are not new. They highlight the need for the Commission and other OASIS users to review this information to ensure that system operators have not conducted system operations in violation of the OASIS standards of conduct. NUCOR argues that only by requiring the same-time disclosure of utility generation data used for economic dispatch can we be sure that unduly preferential treatment by means of a Transmission Provider's own generation will not occur. We do not quarrel with the possibility of affiliate abuse raised by NUCOR. However, NUCOR still has not persuaded us that it is necessary to post these data. If experience shows that the concerns raised by NUCOR are a significant problem, we can consider further actions in the future.[68]

d. Reporting of Network Service Usage

Rehearing Request

CCEM argues that the Commission erred by not requiring Transmission Providers to report network service usage monthly.[69]

Commission Conclusion

CCEM does not state what it means by monthly network service usage or explain why the Transmission Provider should be required to report the data. In any event, we note that the current measure of network usage is load (*i.e.*, billing is based on load-ratio usage). To the extent that utilities use the monthly load data of network customers in calculating ATC, utilities will include load data in the ATC/TTC supporting information required in § 37.6(b)(2)(ii).

4. Posting Firm and Nonfirm ATC Separately

Section 37.6(b)(3) of the OASIS regulations addresses the posting of ATC and TTC for constrained and unconstrained posted paths. For constrained posted paths, the regulations contain separate posting requirements for firm and nonfirm ATC. For unconstrained posted paths, the posting requirements for firm and nonfirm ATC are the same. Section 37.6(b)(3)(ii) does not specifically mention firm and nonfirm ATC.

Rehearing Requests

CCEM and the EPRI/NERC Working Group argue that the Commission erred by failing to require the separate posting of firm ATC and nonfirm ATC for unconstrained posted paths.[70]

Commission Conclusion

The regulations inadvertently left out a reference to firm and nonfirm ATC in the posting requirements for unconstrained posted paths. The regulations at § 37.6(b)(3)(ii) will be modified to correct this and to clarify that firm and nonfirm ATC for unconstrained paths, like firm and nonfirm ATC for constrained paths, must be posted separately.

5. Minimum Term of Firm Point-to-Point Transmission Service

Section 13.1 of the Open Access Final Rule's pro forma tariff specifies that the minimum required term for Firm Point-to-Point Transmission Service is one day.[71] By contrast, § 37.6(b)(3)(i) of the OASIS regulations requires the posting of firm and nonfirm ATC on constrained paths for the next hour and for the next 168 hours (*i.e.*, for the next week).

Rehearing Requests

CCEM argues that the Commission erred by not requiring Transmission Providers to offer hourly firm transmission service.[72] CCEM argues that, if the Commission agrees to change the Open Access *pro forma* tariff to allow for hourly firm transmission service, then the requirement to post hourly transmission service requests on the OASIS should be deferred until the reliability of OASIS sites is established.

EPRI/NERC Working Group argues that the posting of ATC and other information should be consistent with a utility's Open Access *pro forma* tariff. They argue that, as the minimum term for firm ATC is one day under the Open Access pro forma tariff, firm ATC should only be required to be posted daily instead of hourly. Hourly firm ATC would be posted only if it is offered under a revised Open Access tariff.[73]

Commission Conclusion

The OASIS regulations currently require the posting of hourly firm ATC even though the shortest mandated term for firm transmission service under the Open Access pro forma tariff is one day. The Commission believes hourly posting provides useful information to

[66] *See* OASIS Final Rule, 61 FR at 21,746. *See also* OASIS Final Rule, 61 FR at 21,754–55, where we decided not to require the posting of generator run status. Although the OASIS Final Rule does not require the posting of utility generation data, *per se*, this data may be required to be reported, after-the-fact, as part of the Transmission Provider's supporting data for ATC calculations.

[67] NUCOR Rehearing Request at pp. 15–18.

[68] As to NUCOR's contention that after-the-fact review of utility generation data would be ineffectual, we note that if we required the contemporaneous posting of such information on the OASIS (as proposed by NUCOR), our review of any complaint filed as a result of such information would still be conducted after-the-fact.

[69] CCEM Rehearing Request at p. 10.

[70] CCEM Rehearing Request at p. 5 and EPRI/NERC Working Group Rehearing Request at p. 9. For purposes of submitting their request for rehearing, the How Working Group and the What Working Group combined their efforts and submitted a joint request for rehearing on behalf of "the Industry Management Process on How to Implement Transmission Services Information Networks" (EPRI/NERC Working Group).

[71] In Order No. 888–A, the Commission addresses the issue of reducing the minimum term for firm point-to-point transmission service from one day to one hour.

[72] CCEM Rehearing Request at pp. 3–4.

[73] EPRI/NERC Working Group Rehearing Request at p. 9.

customers about the availability of daily service and the likelihood of curtailment during particular hours during the day.

If a Transmission Provider voluntarily offers hourly firm service in its Open Access *pro forma* tariff, it must offer the service through postings on its OASIS. Section 37.6(c)(1) requires Transmission Providers to ''post prices and a summary of the terms and conditions associated with *all* transmission products offered to Transmission Customers.'' [Emphasis added]. The OASIS regulations do not, however, control what services must be provided by Transmission Providers. This is covered by the Open Access Final Rule.

6. Posting of Discounts

Under the OASIS Final Rule, § 37.6(c)(3) of the OASIS regulations requires a Transmission Provider to post (within 24 hours of its adjustment of its ATC calculation) any discounts on transmission service given to non-affiliated customers. This posting was required to remain on the OASIS for 30 days.

Rehearing Requests

EPRI/NERC Working Group asks the Commission to clarify that the purpose of the requirement in § 37.6(c)(3) to post discount information for 30 days is to record the discount and does not constitute a continuing offer of a discount. They suggest dropping this requirement since, under § 37.7, audit data (including data on discounts) must be recorded and retained.[74]

Commission Conclusion

As discussed above in Section IV.E.8, the Commission has adopted a new discounting policy, which is more fully elaborated in Order No. 888–A. This new discounting policy necessitates a number of changes to the OASIS posting requirements.

We have revised and moved the text of § 37.6(c)(3) to § 37.6(c)(4) and have substituted a new § 37.6(c)(3) that requires that any offer of a discount by the Transmission Provider for transmission service must be announced to all potential customers solely by posting on the OASIS.

We have revised the section now designated as § 37.6(c)(4) to no longer treat the posting of transmission service transactions involving the Transmission Provider's wholesale merchant function or affiliates differently from the posting of transactions involving non-affiliates. However, we will require that transactions involving the Transmission Provider's wholesale merchant function or affiliates be identified. The 24-hour delay in posting non-affiliate discounts has been dropped. All transactions for transmission service, agreed to between a Transmission Provider and a customer, regardless of whether they involve a discount or not, must be posted at the time when ATC must be adjusted in response to the transaction. We also have expanded the list of information about the transaction required to be posted.

We have revised and moved the text of § 37.6(d)(2) to § 37.6(d)(3) and have substituted a new § 37.6(d)(2) that requires that any offer of a discount by the Transmission Provider for ancillary service in support of the Transmission Provider's provision of transmission service must be announced to all potential customers solely by posting on the OASIS.

We have revised the section now designated as § 37.6(d)(3) to no longer treat the posting of ancillary service transactions involving the Transmission Provider's wholesale merchant function or affiliates differently from the posting of transactions involving non-affiliates. However, we will require that transactions involving Transmission Provider's wholesale merchant function or affiliates be identified. The 24-hour delay in posting non-affiliate discounts has been dropped. All transactions for ancillary service, agreed to between a Transmission Provider and a customer, regardless of whether they involve a discount or not, must be posted on the OASIS at the time when ATC must be adjusted in response to an associated transmission service transaction, if any. We also have expanded the list of information about the transaction required to be posted.

We have revised § 37.6(e)(1)(i) to require that, with the exception of next-hour service, requests for transmission and ancillary service must be posted prior to the Transmission Provider responding to these requests. This will ensure that other customers can observe any discounts being requested before they are acted on. We also are requiring that all postings of requests be made comparably. We are making this revision to prevent discriminatory practices.

We are revising § 37.6(e)(1)(ii) to expand the information required to be posted on the status of requests for transmission and ancillary service to include the information required in § 37.6(c)(4) and § 37.6(d)(3).

We are deleting the provision formerly found at § 37.6(e)(1)(iii) and are revising § 37.6(e)(3)(i) because, under the Commission's new discounting policy, we no longer will allow the identity of parties to be masked.

We are adding a new provision, at § 37.6(e)(1)(iii), that provides that in the event that a discount is being requested for ancillary services that are not in support of a basic transmission service being provided by the Transmission Provider, such request need not be posted on the OASIS. We add this provision because we are limiting our revisions relating to the posting of discounts for ancillary services to those ancillary services that are in support of basic transmission service provided by a Transmission Provider.

The Phase I OASIS is a passive communication system. A customer sends a request for a discount directly to the Transmission Provider. But the passive nature of the Phase I OASIS prevents the Transmission Provider from sending a reply directly to the customer. Instead, the Transmission Provider posts the reply on the OASIS and the customer must periodically check the node for the reply. A more active communication system would permit the Transmission Provider to send replies directly to customers, as well as to anyone else who is interested. Offers and replies could be exchanged quickly, and the unnecessary delays caused by the cumbersomeness of the passive system would be eliminated. We, therefore, request the How Working Group to consider adding more active capabilities to the OASIS in Phase II.[75]

The Commission's revised discount policy necessitates certain changes to the Standards and Protocols document. The OASIS regulations require that prices offered by a Transmission Provider be posted and that discounts requested by customers be posted. However, under the current Standards and Protocols document, the templates for posting of offered and requested prices do not identify whether these prices constitute a discount and how much of a discount these prices represent. We believe that this information is vitally important to prevent discrimination.

Accordingly, we are requiring that the templates in the Standards and Protocols document dealing with posted offerings (§ 4.3.2), status of transmission service requests (§ 4.3.7), and status of

[74] EPRI/NERC Working Group Rehearing Request at p. 10.

[75] Other benefits of an active system include:

- Making the market more efficient by notifying customers immediately of changes in ATC on specified paths and sending system-wide notices directly to customers as soon as they are issued.
- Making OASIS nodes more responsive by reducing the load on the servers caused by customers periodically checking for messages.

ancillary service requests (§ 4.3.9), be revised to include: (1) The Transmission Provider's filed (ceiling) transmission and ancillary services rates; (2) the Transmission Provider's offering price; (3) the price requested by the customer; and (4) the details of the negotiated transaction. We request that the How Working Group propose the necessary changes in the Standards and Protocols document and the Data Dictionary by June 2, 1997.

Turning to EPRI/NERC Working Group's request that we clarify that the purpose of the requirement in § 37.6(c)(4) (formerly found at § 37.6(c)(3)) to post discount information for 30 days is to record the discount and does not constitute a continuing offer of a discount, we agree that this posting requirement does not constitute an offer of a discount. The purpose of this requirement is to document discounting that might be considered unduly preferential or discriminatory. To serve this purpose, it is important that Transmission Customers have ready access to this information. Posting of discounts provides ready access, while the audit information does not.

7. Secondary Markets

In the OASIS Final Rule, the Commission directed, in § 37.6(c)(4), that customers choosing to use the OASIS to offer transmission capacity (that they have purchased) for resale must post relevant information on the same OASIS used by that customer in purchasing 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. A customer reselling transmission capacity without the use of an OASIS must, nevertheless, inform the original Transmission Provider of the transaction within the time limits prescribed by § 23.1 (''Procedures for Assignment of Transmission Service'') of the Open Access *pro forma* tariff.

Rehearing Requests

CCEM makes three arguments regarding secondary markets. First, CCEM argues that the Commission erred by not allowing the assignee of transmission capacity, or its agent, to schedule the transmission service obtained in the secondary market. Second, CCEM argues that the Commission should clarify that it will not impose onerous regulations on secondary market participants. Third, CCEM argues that the Commission erred by not excluding customers receiving service under pre-Open Access tariffs from participation in the secondary market until they agree to comply with the Open Access *pro forma* tariff.[76]

Commission Conclusion

CCEM's arguments relate more to our findings in Order No. 888 than to the OASIS Final Rule. Accordingly, we incorporate here our findings that we explain in greater detail in Order No. 888–A. First, the Open Access *pro forma* tariff does not prohibit the assignee of transmission capacity from scheduling transmission service with the Transmission Provider. Second, the issues raised by CCEM with respect to the regulation of resellers into the secondary market are fact specific and we will decide them on a case-by-case basis. Third, we reject CCEM's argument that customers receiving service under pre-Open Access tariffs should be excluded from participation in the secondary market until they agree to comply with the Open Access *pro forma* tariff.

8. Masking of Service Request Information

Section 37.6(e)(1)(ii) of the OASIS Final Rule requires the Responsible Party to post certain information about the status of the request. In § 37.6(e)(1)(iii) of the OASIS Final Rule, the Commission allowed the parties to mask the identity of the requester during the negotiation period and for 30 days after the request is accepted, denied or withdrawn.

Under § 37.6(e)(1) and § 37.6(e)(3), all requests for transmission service and all transmission service curtailments or interruptions must be posted on the Transmission Provider's OASIS in accordance with the terms of the Transmission Provider's tariff.[77] Under the OASIS Final Rule, parties to these transactions were allowed to request that their identities be masked for 30 days. *See* §§ 37.6(e)(1)(iii) and 37.6(e)(3)(i).

Rehearing Requests

APPA argues that the Commission erred in permitting Transmission Providers to withhold critical market information about requests for transmission and ancillary services. APPA and Blue Ridge believe that the 30-day masking period for the identity of the requester is inappropriate. They claim that the Commission failed to require posting of the price, quantity, and any other relevant terms or conditions associated with a request for service at the time when the provider accepts the request. They argue that withholding the precise terms of a proposed transaction and the identity of parties denies other market participants the opportunity to make informed decisions, is potentially discriminatory, and inefficient. They argue that data provided 30 days later are of little use to market participants.[78]

CCEM identifies an apparent conflict between the OASIS regulations and OASIS Final Rule preamble on the posting of denials. It asks the Commission to clarify that Transmission Providers need not post, for reasons other than those related to ATC, the reason for any denial of transmission service on an OASIS. A requester can, however, request a fuller explanation.[79]

EEI argues that masking the identities of requesters should not apply to system operators. EEI argues that system operators need to know all the parties to a transaction to ensure reliability and to ensure equity in the treatment of customers.[80]

NE Public Power District argues that certain provisions in the Final Rule dealing with confidentiality (*i.e.*, §§ 37.6(e)(1)(iii) and 37.6(e)(3)(i)) are in conflict with Nebraska state law. NE Public Power District explains that it is subject to state freedom of information laws and must disclose commercially sensitive information such as the identity of a customer seeking transmission service, unless the information constitutes an exempt trade secret.[81] NE Public Power District maintains that utilities subject to local freedom of information laws should be given the option to conform their conduct to those laws.

Commission Conclusion

We agree with APPA that the masking provision should be dropped and we are amending our regulations accordingly. We are making this decision as part of our new discounting policy, that we explain more fully above and in Order No. 888–A. Consistent with this finding, we request that the How Working Group eliminate any references in the Standards and Protocols document to masking the identities of parties (*e.g.*, § 4.3.7(b)). This should be done in concert with the report to be submitted

[76] CCEM Rehearing Request at pp. 6–7.

[77] The issue of the timing of when requests for transmission service, responses thereto, curtailments, and interruptions must be posted on the OASIS is discussed in section IV.G.9 below.

[78] APPA Rehearing Request at pp. 19–21 and Blue Ridge Rehearing Request at p. 39.

[79] CCEM Rehearing Request at pp. 11–12.

[80] EEI Rehearing Request at p. 49.

[81] NE Public Power District Rehearing Request at p. 14.

no later than June 2, 1997. Moreover, EEI's concern that the masking of parties' identities would apply to system operators is now moot. NE Public Power District's concerns are also moot.

We agree with CCEM that language in the preamble of the OASIS Final Rule can be interpreted as being inconsistent with the requirement in § 37.6(e)(2)(i) to provide the reasons why requests for service are denied. However, consistent with the Commission's new discounting policy, we will interpret § 37.6(e)(2)(i) to require Transmission Providers to post the reasons for a denial of a request for service on the OASIS for review by all OASIS users.

We will also take this opportunity to clarify that § 37.6(e) applies not only to requests for transmission service, but also to requests for ancillary service. Although this was the intent of the OASIS Final Rule, it was not clearly stated. We will make the necessary revisions to make this clear.

9. Requests for Service Made on the OASIS During Phase I

On December 23, 1996, the How Working Group filed a letter requesting clarification of whether the Commission intended, in the OASIS Final Rule, to require that the OASIS serve as a ''next hour'' reservation tool during Phase 1 of OASIS implementation. The letter stated:

> It was the interpretation of the How Working Group that a Provider would accept reservation requests after 2 p.m. of the preceding day, only if practical. Otherwise, these requests would be accepted off-line and posted after-the-fact. It was our view that ''next hour'' functionality was not feasible in Phase 1.

In response, the Commission issued an order explaining that the OASIS Final Rule makes a clear distinction between reserving transmission service and scheduling transmission service.[82] The Commission further explained that the Phase 1 OASIS regulations create a mechanism for making reservations of transmission service, while the inclusion of energy scheduling as part of the OASIS requirements was left as a Phase 2 OASIS issue. Nevertheless, the Commission acknowledged that ''for near-term transactions, the distinction between scheduling and reservations tends to blur.'' This left the problem raised by the How Working Group's letter. To wit,

> [t]he OASIS regulations provide, at 18 C.F.R. § 37.6(e)(1), that ''[a]ll requests for transmission services offered by Transmission Providers under the *pro forma* tariff must be made on the OASIS.'' Notwithstanding the clear language of this regulation, the How Working Group would like to accommodate requests for service, made after 2:00 p.m. of the day preceding the commencement of such service, off the OASIS and states that it is not feasible to handle such requests on the OASIS during Phase 1. [[83]]

To resolve this difficulty, the Commission clarified in a recent order that,

> during Phase I, a request for transmission service made after 2:00 p.m. of the day preceding the commencement of such service, will be ''made on the OASIS'' if it is made directly on the OASIS, or, if it is made by facsimile or telephone *and* promptly (within one hour) posted on the OASIS by the Transmission Provider. In all other circumstances, requests for transmission service must be made exclusively on the OASIS. [[84]]

As part of the Commission's revised discount policy, *see* discussion in Section IV.G.6 and Order No. 888–A, we have required Transmission Providers to post requests for transmission and ancillary services, including requests for discounts, on the OASIS prior to taking action on those requests.[85] This policy applies to all requests for discounts for transmission and/or ancillary service with the exception of requests for next-hour service during Phase I.[86]

For next-hour service requests, the Transmission Provider, during Phase I, must post the request for discounted service on the OASIS, as soon as possible, but in no event later than one hour after the request for a discount is received.

In the event that a discount is being requested for ancillary services that are not in support of a basic transmission service being offered by the Transmission Provider, this need not be posted on the OASIS.[87]

10. Delay in Posting Requests for Hourly Transmission Service and Schedule Information

Section 37.6(e) requires a Transmission Provider to post on the OASIS requests for transmission service that is offered by that Transmission Provider under its Open Access *pro forma* tariff, in accordance with its tariff, the FPA, and Commission regulations. Section 37.6(f) requires information about transmission service schedules to be recorded and available for download from the OASIS. This information must be available within seven calendar days of when the service is scheduled.

Rehearing Requests

CCEM requests that the Commission clarify that Responsible Parties must post requests for hourly firm and nonfirm transmission within the next hour following the request.[88]

APPA and Blue Ridge argue that the seven-day delay in posting transmission schedule data is potentially discriminatory and makes the data meaningless for hourly or daily transactions. They ask that Responsible Parties post schedule information when they update postings of ATC or, at latest, when service begins.[89]

Commission Conclusion

The OASIS regulations currently do not specify how soon the Responsible Party must post a request for service after it is received. However, under our new discounting policy we are requiring such postings to be made prior to the Transmission Provider responding to the request. Moreover, although we are not adopting a specific time period for such postings, as requested by CCEM, we are adding a requirement that all such postings be made on a comparable basis, to prevent discriminatory practices.

The Phase I OASIS is a transmission information and service application system. The Commission accepts the industry's position that including scheduling of transmission service in the Phase I OASIS is not possible. The Commission strongly encourages the industry to consider including transmission service scheduling in Phase II of the OASIS.

The reporting of schedule information serves the same purpose as the audit information (*i.e.,* to document discriminatory practices). The Commission does not intend schedule information to supplement ATC

[82] *See* Open Access Same-time Information System and Standards of Conduct, 77 FERC ¶ 61,335 at 62,491 (1996) (Clarifying Order).

[83] Letter dated December 23, 1996 from the How Working Group. The 2:00 p.m. deadline is consistent with § 14.6 of the Open Access *pro forma* tariff, which provides: ''Schedules for Non-Firm Point-to-Point Transmission Service must be submitted to the Transmission Provider no later than 2:00 p.m. . . . of the day prior to commencement of such service. Schedules submitted after 2:00 p.m. will be accommodated, if practicable.'' *See* Clarifying Order, 77 FERC at 62,492, n.4.

[84] *Id.* (Emphasis in original).

[85] *See* § 37.6(e)(1)(i).

[86] *See* § 37.6(e)(1)(ii).

[87] See § 37.6(e)(1)(iii).

[88] CCEM Rehearing Request at pp. 4–5. We note that CCEM's rehearing request regarding hourly firm transmission service is misplaced. The Commission has rejected hourly firm point-to-point transmission service as a mandatory service to be provided under the Open Access *pro forma* tariff. *See* Order No. 888, FERC Stats & Regs. at 31,752.

[89] APPA Rehearing Request at p. 23 and Blue Ridge Rehearing Request at p. 40.

postings on a same-time basis during Phase I.

11. Liability for Accuracy of ATC/TTC Estimates

In the OASIS Final Rule, the Commission found that the responsibility for assuring the reliability and accuracy of data supplied by third parties rests with those third parties and not with the public utility that posts this information on the OASIS as an accommodation.[90] As to the accuracy of a Transmission Provider's own estimates of its ATC and TTC, the OASIS Final Rule provides that Transmission Providers are required to post the amounts ''expected to be available'' (§ 37.6(b)) but does not directly address whether (and to what extent) Transmission Providers are liable for the accuracy of good faith estimates made in accordance with prescribed procedures.

Rehearing Request

CSW argues that Transmission Providers should not be liable for the accuracy of ATC & TTC estimates made in good faith and in accordance with the company's published procedures.[91]

Commission Conclusion

As further discussed in Order No. 888–A, the Commission will not revise the Open Access *pro forma* tariff, as requested by CSW, to provide that a Transmission Provider will not be liable for errors in an estimate made in good faith or in accordance with its published procedure, because we believe that a utility should have the same liability standard for operating an OASIS as it has for its other operations.[92]

H. Section 37.7—Auditing Transmission Service Information

The OASIS regulations require that all OASIS database transactions, except ''want ads'' and ''other communications'', are to be stored and remain available for download for 90 days. After 90 days, the audit data are available on request for three years.

Rehearing Requests

EEI argues that the retention period for audit data retained under § 37.7(b) is excessive and should be reduced from 90 days to 7 days. EEI argues that, beyond 7 days, the data could be provided off-line, upon request.[93]

Similarly, EPRI/NERC Working Group (with APPA dissenting) argues that the Commission should reduce the on-line availability of the ATC/TTC data in the audit file from 90 to 10 days. They claim that the longer time limit is burdensome and unfeasible and suggest making the data available off-line.[94]

Commission Conclusion

The Commission agrees with the proposal of the EPRI/NERC Working Group majority that we should reduce the amount of time that the audit file remains on-line. However, we believe that ten days may not be long enough to provide OASIS users with sufficient time to evaluate these data. In our judgment, 20 calendar days is a period that will allow OASIS users who wish to do so adequate time to find and download these data (even allowing for weekends or holidays) without unduly burdening Transmission Providers. Therefore, we will modify the regulations at § 37.7(b) to shorten—from 90 to 20 days—the time during which ATC/TTC postings must remain available on the OASIS for download. The data will, however, remain available (upon request) for three years from the date on which they are first posted.

We will take this opportunity to correct an omission in § 37.6(g)(3). As written, this provision currently does not specify the retention period for notices of employee transfers. We will correct this omission by specifying that the posting requirements for notices of employee transfers are the same as those provided in § 37.7 for audit data postings. We request that the How Working Group propose the necessary template (for notices of employee transfers) to be included in the Standards and Protocols document.

We also will take this opportunity to clarify that the audit data required to be made available for three years under § 37.7(b) are to be made available upon request for download in the same electronic form as used when they originally were posted on the OASIS.

I. Standards and Communication Protocols

1. CCEM's Suggested Changes to the Standards and Protocols Document

The OASIS Final Rule was accompanied by a Standards and Protocols document, revised on September 10, 1996, to help ensure that each OASIS will provide information in a uniform manner.[95] The publication details the Phase I requirements for technical issues related to the implementation and use of an OASIS (*i.e.*, a compilation of OASIS standards and communication protocols).

Rehearing Request

CCEM argues that the Commission should clarify certain technical aspects of the templates in the OASIS Standards and Protocols document. We will discuss these various suggested revisions separately.

a. Service Request Priorities

The Open Access *pro forma* tariff requires Transmission Providers to respond to customer requests for point-to-point service within a certain time limit depending on the type of service requested.[96] The OASIS Standards and Protocols document states that ''[i]f a purchase request is approved by the Seller, then it must be again confirmed by the Customer. Once the customer confirms an approved purchase, a reservation for those services is considered to exist, unless later the reservation is reassigned or displaced.'' [97]

Rehearing Request

CCEM asks the Commission to clarify priorities between competing requests for service. They also ask that Transmission Customers be allowed to confirm a purchase request before it has been approved by the Transmission Provider.[98]

EPRI/NERC Working Group requests that the Commission: (1) specify a time limit for customer confirmation of accepted requests for service; (2) eliminate the confirmation step; or (3) handle confirmation limits in umbrella service agreements.[99]

Commission Conclusion

The requirement that a customer confirm its request for service appears in the OASIS Standards and Protocols document (and not in the Open Access *pro forma* tariff or 18 CFR Part 37). Although the easiest approach might be to eliminate the confirmation step, the Commission is reluctant to modify the OASIS Standards and Protocols document at this late date. The Commission is also reluctant to specify confirmation time limits without first soliciting the views of representative industry segments. Accordingly, the

[90] *See* 18 CFR § 37.6(g)(2) and OASIS Final Rule, 61 FR at 21,755.

[91] CSW Rehearing Request at pp. 2–6.

[92] *See, e.g.,* Texas Eastern Transmission Corporation, 62 FERC ¶ 61,015 at 61,107 (1993).

[93] /EEI Rehearing Request at p. 52.

[94] EPRI/NERC Working Group Rehearing Request at pp. 9–10.

[95] *See supra* note 4.

[96] *See* Open Access *pro forma* tariff at §§ 17.5 and 18.4.

[97] *See* Standards and Protocols document at § 3.6(b).

[98] CCEM Rehearing Request at p. 7.

[99] EPRI/NERC Working Group letter dated July 3, 1996 at pp. 1–2.

Commission requests that the industry address this issue as part of the Phase II report due on or before August 4, 1997.

As to EPRI/NERC Working Group's suggestion of handling confirmation limits in umbrella service agreements, we find this acceptable, for the time being, as long as Transmission Providers treat all customers, including their own wholesale merchant employees, comparably.

b. Clarification of the Requirement to Post, Upload, and Download Information

In the OASIS Final Rule, the Commission discussed the necessity for Hypertext Mark-up Language (HTML) screen displays and stated that this information also needed to be made available for downloading.[100] The Commission also required OASIS sites to be set up in a manner that will allow customers to upload certain information to OASIS nodes.

Rehearing Request

CCEM requests that the Commission clarify that when the OASIS Final Rule makes an individual reference to ''uploading'', ''downloading'', or ''posting'' requirements (without expressly making a reference to all three of these requirements), the Commission, nevertheless, intended to require, as appropriate, a collective requirement to upload, download, and post the information at issue. CCEM points out that uploading and downloading are computer to computer transactions, while posting is an on-line function. CCEM argues that, in order for the OASIS system to function effectively in providing open access Transmission Customers with information through electronic means, uploading and downloading should always be required as an alternative to comparable on-line services.[101]

Commission Conclusion

Section 4.3.1 of the revised Standards and Protocols document, issued subsequent to CCEM's request, specifies what type of information may be uploaded to, or downloaded from, OASIS nodes. Thus, CCEM's goal of clarifying the requirements for uploading, downloading, and posting has been met. We, therefore, find that it is not necessary to broadly reinterpret the terms used in the OASIS Final Rule, as urged by CCEM.

[100] *See* OASIS Final Rule, 61 FR at 21,756.

[101] CCEM Rehearing Request at p. 12.

c. Sequence of Data Elements Appearing in Templates

Section 4.2.4.2 of the revised Standards and Protocol document discusses the format of downloadable files. The narrative in § 4.2.4.2 2.d states:

> The DATA—ROWS record contains the number of data records following the COLUMN—HEADERS. The COLUMN—HEADERS record contains the template element name for each field that is required in the Template, in the exact order as listed in the Template. * * *
>
> The Template information then follows as records which correspond one-to-one with the column headings.

Rehearing Request

CCEM requests clarification that the data elements that make up the templates in the Standards and Protocols document are fixed in sequence and in number. CCEM argues that because computer systems will be established on the basis of the templates outlined in the Standards and Protocols document, including the sequence of templates and the number of data elements, it is important that the order of the data provided in the templates not be shuffled. Otherwise, problems may occur in the transfer and receipt of information between computer systems.[102]

Commission Conclusion

To avoid any possible confusion, we hereby clarify that the Standards and Protocols document requires that the data elements in the templates are fixed in sequence and number, and are not to differ from OASIS node to OASIS node. However, the Commission will continue to order revisions to the Standards and Protocols document periodically (thus implementing across-the-board changes to the templates for all OASIS nodes), as necessary.

2. Standardized Format for Electronic Tariff Filings

In the OASIS Final Rule, the Commission found that utilities must provide tariff downloads from their OASIS sites in the same format that they use to file their tariffs with the Commission. Order No. 888 permitted tariff filings to be in any word processor format.

Rehearing Request

APPA argues that the standardized electronic format for tariffs needs to be specified and recommends the use of either ASCII or HTML.[103]

[102] *Id.*

[103] APPA Rehearing Request at p. 25.

Commission Conclusion

The Commission's order clarifying Order Nos. 888 and 889 compliance matters resolved the issue raised by APPA by requiring that tariffs be filed in either Wordperfect 5.1/5.2 or ASCII format.[104] However, in the near future, the Commission expects to adopt another standard word processor for its own uses (*i.e.*, Wordperfect 6.1). The Commission will, therefore, modify the finding in the *Clarifying Order* to accept postings of tariff filings on the OASIS in the ASCII format or in whatever standard word processor format is currently authorized by the Commission for its own uses.[105] Once posted, a tariff posting will remain available for download in its original format.

3. Company Codes and Identification Displays

In the OASIS Final Rule, the Commission required the use of ''DUNS numbers'' to identify transmission owning utilities and customers on OASIS nodes.[106]

Rehearing Requests

APPA argues that, notwithstanding claims to the contrary, the use of DUNS numbers could result in costs being incurred by OASIS users. APPA also argues that, because Dun & Bradstreet also owns Moody's Investors Services, DUNS numbers may somehow allow Dun & Bradstreet/Moody's customers to obtain access to confidential information about APPA members. Accordingly, APPA requests that the Commission use the EIA (Energy Information Agency) UCode in lieu of DUNS numbers to identify transmission owning utilities and OASIS customers.[107]

CCEM requests that the Commission clarify that when information is uploaded and downloaded, the DUNS number identification of the parties be the only field required to identify a company. CCEM also requests clarification that the Commission require that for purposes of the HTML displays, the minimum data element to

[104] Promoting Wholesale Competition Through Open-Access Non-Discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Open Access Same-Time Information System and Standards of Conduct, Order Clarifying Order Nos. 888 and 889, 76 FERC ¶ 61,009 at 61,026 (1996) (*Clarifying Order*).

[105] A review of CIPS, or any successor, will show what standard word processor is currently authorized by the Commission for its own uses.

[106] ''DUNS numbers'' refer to the Data Universal Numbering System, maintained by Dun and Bradstreet.

[107] APPA Rehearing Request at p. 25.

be displayed should be the company's alias/initials.[108]

In addition, CCEM requests that Transmission Providers be required to maintain an additional display containing a cross-reference of DUNS number, full company name, and alias/ initials. CCEM argues that the cross-reference will reduce confusion on the OASIS.[109]

Commission Conclusion

The industry-wide Internet site on the WWW (http:/www.tsin.com) reports that Dun & Bradstreet will issue DUNS numbers at no charge and provides instructions and procedures for applying for a DUNS number at no cost. This representation is consistent with our experience in issuing DUNS numbers for natural gas pipelines and their customers. We, therefore, find APPA's concerns about the costs of DUNS numbers to be unwarranted.

As to APPA's concern about DUNS numbers somehow giving Moody's customers unrestricted access to otherwise restricted information, we do not find this concern convincing. The Commission has several years'' experience with requiring the use of DUNS numbers for similar identification purposes in the natural gas pipeline industry and has not received any complaints along these lines.

We decline to adopt CCEM's proposal concerning identification fields and a data element displays. The industry is in the midst of implementing OASIS standards and we are reluctant to modify the Standards and Protocols document at this time unless there is a serious need for the modification. CCEM's proposal is one that may somewhat improve the efficiency of OASIS operations, but an OASIS can operate without it, and, with experience, other solutions may prove preferable. We request that the industry consider CCEM's proposal when developing standards for OASIS Phase II implementation.

We agree with CCEM that an additional display, such as a cross-reference of possible business partners and their various identification codes and symbols, would greatly enhance the industry's ability to transact business. Subsequent to CCEM's request, the ''TSIN'' WWW site began providing such a cross-reference. As long as this Internet site continues to provide this information for the entire industry, there is no need for individual Transmission Providers to do so.

[108] CCEM Rehearing Request at p. 13.

[109] *Id.*

4. Common Location Codes

In the preamble to the OASIS Final Rule, we stated that we were abandoning the proposal in the RIN NOPR to require that the OASIS incorporate a system for location codes. We requested that the industry continue its efforts to develop a common naming convention to be implemented as soon as practicable.

Rehearing Request

CCEM argues that the Commission should modify the OASIS Final Rule to include a requirement that Transmission Providers provide a downloadable on-line listing of all PORs and PODs that includes point name, point alias, and point code. CCEM also requests that when downloading this information, the customer should have the ability to download only those aspects of the listing that have changed over a user-defined time period.[110]

Commission Conclusion

After CCEM filed its rehearing request, the Standards and Protocols document was revised to require that this information be provided.[111]

5. Time by Which Hourly Postings Must be Made Available

The OASIS Final Rule requires that updates of hourly postings under § 37.6(b)(3)(i)(C)(2) are to be made on the hour.

Rehearing Request

CCEM requests that the Commission clarify that all hourly postings will be available no later than ''on the hour.'' CCEM argues that these requirements will be critical if computer-to-computer interfaces are to be accomplished with reliability and comparability.[112]

Commission Conclusion

Subsequent to CCEM's request, the Commission issued a revised Standards and Protocol document that defines permissible deviations from the hourly posting requirement.[113] The Transmission Provider's most recent transmission services information must be available on the OASIS node within five minutes of its required posting time at least 98 percent of the time. The remaining two percent of the time, the transmission services information must be available within ten minutes of its scheduled posting time.[114] We are satisfied with the resolution of this issue in the revised Standards and Protocols document, at least for the time being. However, the industry may want to address this issue again, in Phase II, after it has more experience transacting business on the OASIS.

[110] *Id.*

[111] *See* Standards and Protocols document at § 4.3.5.

[112] CCEM Rehearing Request at p. 13.

[113] *See supra* note 4.

[114] *See* Standards and Protocols document at § 5.7.

J. Mechanism for Recovering Oasis Expenses

In the preamble to the OASIS Final Rule, the Commission concluded that it is appropriate that all wholesale Transmission Customers and all unbundled retail Transmission Customers pay a share of OASIS development costs in their rates. The costs of developing an OASIS are to be included in unbundled transmission rates with variable costs of operating an OASIS to be recovered, to the extent possible, in usage fees. Recovery of OASIS costs is left to individual rate proceedings.[115]

Rehearing Requests

EEI argues that the costs of operating an OASIS should be recoverable in supplements that the Transmission Providers file to their rate schedules on a company-specific basis. They ask that Transmission Providers not be required to amend their approved tariffs to seek recovery of OASIS expenses. They argue that refiling would be a problem because it would entail unnecessary expenses, because the level of such expenses is subject to change, and because the OASIS requirements are still evolving and the systems are not yet complete.[116]

Commission Conclusion

EEI is asking the Commission to allow utilities to automatically adjust their transmission rates to recover their OASIS costs without filing for a change in rates. The Commission has allowed this sort of automatic rate adjustment for fuel costs through fuel adjustment clauses, but only because fuel costs are a significant portion of total costs and can be volatile. OASIS costs are neither. We deny EEI's request.

K. Section 37.8—Implementation Schedule; Phases

Order No. 889 provided that all of the requirements prescribed in the standards of conduct were to be complied with and Phase I OASIS sites meeting all the requirements of the OASIS Final Rule were to be in operation by November 1, 1996.[117] This compliance schedule later was modified

[115] *See* OASIS Final Rule, 61 FR at 21,760–61.

[116] EEI Rehearing Request at pp. 54–55.

[117] *See* OASIS Final Rule, 61 FR at 21,764.

(in response to a request from the How Working Group for a two-step time extension) with full compliance required by January 3, 1997.[118] Thus, the date for compliance with Phase I OASIS implementation and for compliance with the standards of conduct has elapsed and the language in § 37.8 is no longer accurate, even as a record of past events. We, therefore, will revise 18 CFR Part 37 to delete this provision.

Rehearing Request

Union argues that it has been given insufficient time to comply and objects to the requirement that OASIS systems must be in place by November 1, 1996. Union argues that compliance by such an early date will require the company to incur a considerable effort and expense and will involve the development of intricate electronic information functions, even though the operational requirements for OASIS sites have not yet been completed.[119]

Commission Conclusion

We find Union's arguments to be moot. As noted above, after Union filed its request for rehearing, the Commission issued a revised Standards and Protocols document that more fully describes the operational requirements of OASIS sites, and granted the request from the How Working Group for a 2-month time extension for compliance with the requirements of Order No. 889. Moreover, the Commission invited comments from interested persons prior to issuing the revised Standards and Protocols document.

V. Regulatory Flexibility Act Certification

The Regulatory Flexibility Act (RFA) [120] requires any proposed or final rule issued by the Commission to contain a description and analysis of the impact that the proposed or final rule would have on small entities or to contain a certification that the rule, if promulgated, will not have a significant economic impact on a substantial number of small entities. Order No. 889 contained a certification under § 605(b) of the RFA that the OASIS Final Rule would not impose a significant economic impact on a substantial number of small entities within the meaning of the RFA.[121]

NRECA challenges this certification.[122] NRECA recognizes that OASIS requirements do not apply unless a non-public utility offers reciprocal transmission service.[123] However, NRECA maintains that business necessity will force non-public utilities to file open access tariffs, and thus subject themselves to OASIS requirements, since, if they do not, ''they will not retain access over the long-term to the nation's bulk power transmission grid—access they must have if they wish to stay in business.'' [124]

In the OASIS Final Rule, we noted that the entities that would have to comply with the Final Rule are public utilities. However, the Commission under appropriate circumstances will grant waiver of the Final Rule requirements to small public utilities. Similarly, it will grant waiver of the reciprocity condition to small non-public utilities. As discussed earlier, in section IV.B.3, the Commission's waiver policy follows the SBA definition of small electric utility.[125]

We disagree with NRECA that non-public utilities must publish open access tariffs or forego access to the nation's bulk power transmission grid. As we noted in the Open Access Final Rule, non-public utilities do not have to offer open access tariffs in order to comply with the open access reciprocity condition; rather, they must offer reciprocal transmission access to those public utility Transmission Providers from whom they receive open access service. Additionally, reciprocal service is voluntary. If non-public utilities do not want to offer reciprocal service, they may continue to seek voluntary, bilateral transmission services from public utilities.[126] We note that since NRECA filed its rehearing comments, the Commission has issued several orders addressing its waiver policy and specific waiver requests. We have granted waivers of the reciprocity provision in the Open Access *pro forma* tariffs and waivers of the requirements of the OASIS Final Rule: approximately 17 small entities have received waivers of the Open Access Final Rule;[127] approximately 36 small entities have received waivers of the requirement to establish and maintain an OASIS and/or the requirement to comply with the standards of conduct requirements of the OASIS Final Rule.[128] We also have granted waiver of the open access tariff reciprocity provision that would apply to ten small non-public utility applicants if they chose to receive open access transmission service, and have determined that 19 small non-public electric utilities that requested exemption from all or part of the Open Access Rule are not public utilities subject to the requirement to file an open access tariff.[129]

Although NRECA speculates that it may be burdensome for small non-public utilities to file for waiver of our Open Access and OASIS Final Rules, many small public and non-public utilities have found little or no problem in obtaining waivers when they are properly justified under our waiver standards. As the Commission's decisions show, the Commission is carefully evaluating the effect of the OASIS Final Rule on small electric utilities and is granting waivers where appropriate, thus mitigating the effect of that rule on small public and non-public utilities.

Given that this order makes only minor revisions to Order No. 889, none of which are substantive, and that we are granting waivers from the requirements of the OASIS Final Rule to small entities where appropriate, we reaffirm our earlier certification that the OASIS Final Rule will not have a significant economic impact on a substantial number of small entities and that no regulatory flexibility analysis is required pursuant to § 603 of the RFA.

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[118] *See supra* note 6.

[119] Union Rehearing Request at pp. 53–54, 56–57. We also note that as of the issuance of this order, Union's OASIS site is in operation.

[120] 5 U.S.C. §§ 601–612.

[121] *See* OASIS Final Rule, 61 FR at 21,762–63.

[122] NRECA Rehearing Request at pp. 42–48. On November 1, 1996, NRECA filed a supplement to its request for rehearing and clarifications. We will accept NRECA's pleading as a request for clarification and/or a motion for reconsideration, and not as a request for rehearing, because it was not filed within the 30-day statutory time limit for rehearing requests. *See* 16 U.S.C. § 8251(a).

[123] OASIS Final Rule, 61 FR at 21,742.

[124] NRECA Rehearing Request at pp. 42–43.

[125] *See* 5 U.S.C. §§ 601(3) and 601(6) and 15 U.S.C. § 632(a). The RFA defines a small entity as one that is independently owned and not dominant in its field of operation. *See* 15 U.S.C. § 632(a). The Small Business Administration defines a small electric utility as one that disposes of 4 million MWh or less of electric energy in a given year. *See* 13 CFR 121.601 (Major Group 49–Electric, Gas and Sanitary Services) (1995).

In the Open Access Final Rule, we concluded that, under these definitions, the Open Access Final Rule would not have a significant economic impact on a substantial number of small entities. We reaffirm that conclusion in Order No. 888–A, which is being issued contemporaneously with this order on rehearing. This same conclusion is warranted here, because Order No. 889 and this order on rehearing only implement the OASIS requirements of the Open Access Final Rule.

[126] Open Access Final Rule, 61 FR at 21,540 and 21,691.

[127] *See* Order No. 888–A at Section VI.

[128] *See Central Electric,* 77 FERC at 61,311, 61,313–317 (3 waivers, including 2 for entities later found non-jurisdictional); *Northern States* (21 waivers); *Black Creek* (3 waivers); *Midwest* (5 waivers); UtiliCorp, *et al.,* 77 FERC 61,027 (1997) (2 waivers); *Soyland* (6 waivers); and Dakota (3 waivers). Of the entities granted waivers by these orders, at least 36 involve small public utilities.

[129] *See Central Electric; Niabrara;* and *Dakota.*

VI. Environmental Statement

Order Nos. 888 and 889 were the joint subjects of the Final Environmental Impact Statement issued in the Open Access NOPR proceeding in Docket Nos. RM95–8–000 and RM94–7–001 on April 12, 1996. Given that this order makes only minor revisions to Order No. 889, none of which is substantive, no separate environmental assessment or environmental impact statement has been prepared in this proceeding.

VII. Information Collection Statement

Order No. 889 contained an information collection statement for which the Commission obtained approval from the Office of Management and Budget (OMB). Given that this order makes only minor revisions to Order No. 889, none of which is substantive, OMB approval for this order will not be necessary. However, the Commission will send a copy of this order to OMB, for informational purposes only.

The information reporting requirements under this order are virtually unchanged from those contained in Order No. 889.[130] Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426 [Attention Michael Miller, Information Services Division, (202) 208–1415], and the Office of Management and Budget [Attention: Desk Officer for the Federal Energy Regulatory Commission, (202) 395–3087].

VIII. Effective Date

The changes ordered in this order on rehearing will become effective on May 13, 1997. By issuing this order, we are not further delaying the requirement to comply with Order No. 889 by January 3, 1997. The current requirements of Part 37 will remain in full effect until the changes required by this order become effective.

[130] As discussed in section IV.E.3 above, to aid in our monitoring efforts, we are modifying §§ 37.4 and 37.6 to require the posting of the Transmission Provider logs already required (by the OASIS Final Rule) to be maintained. We also are revising the Standards and Protocols document to specify the templates for posting discounts to be consistent with our revised discount policy. However, given that this information was already required to be assembled and available for audit, these additional posting requirements will have only a negligible effect on the information collection requirement. Moreover, these effects are more than offset by the revision to § 37.7(b) that reduces, from 90 days to 20 days, the time during which ATC/TTC postings must remain available for download on the OASIS.

List of Subjects in 18 CFR Part 37

Electric power plants, Electric utilities.

By the Commission.

Lois D. Cashell,

Secretary.

In consideration of the foregoing, the Commission amends Part 37 in Chapter I, Title 18, *Code of Federal Regulations,* as set forth below.

PART 37—OPEN ACCESS SAME-TIME INFORMATION SYSTEMS AND STANDARDS OF CONDUCT FOR PUBLIC UTILITIES

1. 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.

2. Section 37.3 is amended by revising paragraph (e) to read as follows:

§ 37.3 Definitions.

* * * * *

(e) *Wholesale merchant function* means the sale for resale of electric energy in interstate commerce.

* * * * *

3. Section 37.4 is amended by removing paragraphs (b)(5)(v) and (b)(5)(vi), and by revising paragraphs (b)(5)(iii) and (b)(5)(iv) to read as follows:

§ 37.4 Standards of conduct.

* * * * *

(b) * * *

(5) * * *

(iii) The Transmission Provider must keep a log, available for Commission audit, detailing the circumstances and manner in which it exercised its discretion under any terms of the tariff. The information contained in this log is to be posted on the OASIS as provided in § 37.6(g)(4).

(iv) The Transmission Provider may not, through its tariffs or otherwise, give preference to sales for resale by the wholesale merchant function or by any affiliate, over the interests of any other wholesale customer in matters relating to the sale or purchase of transmission service (including issues of price, curtailments, scheduling, priority, ancillary services, etc.).

* * * * *

4. Section 37.6 is amended by revising paragraphs (b)(3)(ii)(A), (c)(3), (c)(4), (d)(2), (d)(3), (d)(4), (e)(1)(i), (e)(1)(ii), (e)(1)(iii), (e)(3)(i), and (g)(3) and by adding paragraphs (b)(1)(iv), (c)(5), (d)(5), (e)(1)(iv), and (g)(4) to read as follows:

§ 37.6 Information to be posted on an OASIS.

* * * * *

(b) * * *

(1) * * *

(iv) The word ''*interconnection*'', as used in the definition of ''posted path'', means all facilities connecting two adjacent systems or control areas.

* * * * *

(3) * * *

(ii) *Unconstrained posted paths.* (A) Postings of firm and nonfirm ATC and TTC 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 and TTC 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.

* * * * *

(c) *Posting transmission service products and prices.*

* * * * *

(3) Any offer of a discount for any transmission service made by the Transmission Provider must be announced to all potential customers solely by posting on the OASIS.

(4) For any transaction for transmission service agreed to by the Transmission Provider and a customer, the Transmission Provider (at the time when ATC must be adjusted in response to the transaction), must post on the OASIS (and make available for download) information describing the transaction (including: price; quantity; points of receipt and delivery; length and type of service; identification of whether the transaction involves the Transmission Provider's wholesale merchant function or any affiliate; identification of what, if any, ancillary service transactions are associated with this transmission service transaction; 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.

(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 one 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. A customer reselling transmission capacity without the use of an OASIS must, nevertheless, inform the original Transmission Provider of the transaction within any time limits prescribed by the Transmission Provider's tariff or in a contract or service agreement between the Transmission Provider and a customer.

(d) Posting ancillary service offerings and prices.

* * * * *

(2) Any offer of a discount for any ancillary service made by the Transmission Provider must be announced to all potential customers solely by posting on the OASIS.

(3) For any transaction for ancillary service agreed to by the Transmission Provider and a customer, the Transmission Provider (at the time when ATC must be adjusted in response to an associated transmission service transaction, if any), must post on the OASIS (and make available for download) information describing the transaction (including: date and time when the agreement was entered into; price; quantity; length and type of service; identification of whether the transaction involves the Transmission Provider's wholesale merchant function or any affiliate; identification of what, if any, transmission service transactions are associated with this ancillary service transaction; 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.

(4) Any other interconnected operations service offered by the Transmission Provider may be posted, with the price for that service.

(5) Any entity offering an ancillary service shall have the right to post the offering of that service on the OASIS if the service is one required to be offered by the Transmission Provider under the *pro forma* tariff prescribed by part 35 of this chapter. Any entity may also post any other interconnected operations service voluntarily offered by the Transmission Provider. Postings by customers and third parties must be on the same page, and in the same format, as postings of the Transmission Provider.

(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, 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). The Transmission Provider must post all requests for transmission service and for ancillary service comparably. Requests for transmission and ancillary service, and 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 § 37.6(c)(4), § 37.6(d)(3), 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).

* * * * *

(3) *Posting when a transaction is curtailed or interrupted.*

(i) When any transaction is curtailed or interrupted, the Transmission Provider must post notice of the curtailment or interruption on the OASIS, and the Transmission Provider must state on the OASIS the reason why the transaction could not be continued or completed.

* * * * *

(g) * * *

(3) Notices of transfers of personnel shall be posted as described in § 37.4(b)(2). The posting requirements are the same as those provided in § 37.7 for audit data postings.

(4) Logs detailing the circumstances and manner in which a Transmission Provider or Responsible Party exercised its discretion under any terms of the tariff shall be posted as described in § 37.4(b)(5)(iii). The posting requirements are the same as those provided in § 37.7 for audit data postings.

5. Section 37.7 is amended by revising paragraph (b) 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 three years from the date when they are first posted in the same electronic form as used when they originally were posted on the OASIS.

§ 37.8 [Removed]

6. Section 37.8 is removed.

[Note: This attachment will not appear in the Code of Federal Regulations.]

Attachment 1

List of Requests for Rehearing of Order No. 889

(This list includes all requests for rehearing that made a reference to Order No. 889 in their text and/or caption)

Company Name (Abbreviation)

1. Alabama Municipal Electric Authority (AL MEA)*
2. Alabama Electric Cooperative, Inc. and South Mississippi Electric Power Association (AL EC)*
3. Operating Companies of American Electric Power System (AEP)
4. American Public Power Association (APPA)
5. Basin Electric Power Cooperative (Basin EC)*
6. Blue Ridge Power Agency, Northeast Texas Electric Cooperative, Inc., Sam Rayburn G&T Electric Cooperative, Inc., and Tex-La Electric Cooperative of Texas, Inc. (Blue Ridge)
7. Ralph R. Mabey, Trustee for Cajun Electric Power Cooperative, Inc. (Cajun)*
8. Carolina Power & Light Company (Carolina P&L)
9. Central Power and Light Company, West Texas Utilities Company, Public Service Company of Oklahoma, and Southwestern Electric Power Company (Central P&L)*
10. Central Montana Electric Power Cooperative, Inc. (Central Montana EC)*
11. Cities of Benton, Conway, North Little Rock, Osceola, Prescott, West Memphis, Arkansas and the Farmers Electric Cooperative Corporation (AK Cities)*
12. City of Redding, CA (Redding)
13. City of Santa Clara, CA (Santa Clara)*
14. Coalition for a Competitive Electric Market (CCEM)
15. Colorado Association of Municipal Utilities (CAMU)

16. Consolidated Edison Company of New York, Inc., Long Island Lighting Company, New York State Electric & Gas Corporation, and Rochester Gas and Electric Corporation (ConEd)
17. Cooperative Power (Cooperative Power)*
18. Edison Electric Institute (EEI)
19. El Paso Electric Company (El Paso)
20. Electric Power Research Institute (EPRI) and North American Electric Reliability Council (NERC), on behalf of Industry Management Process on ''how'' to implement Transmission Services Information Networks (EPRI/NERC Working Group)
21. Florida Power & Light Company (FPL)*
22. Florida Power Corporation (Florida Power Corp)*
23. Hoosier Energy Rural Electric Cooperative, Inc. (Hoosier EC)*
24. Illinois Power Company (Illinois Power)
25. Indianapolis Power & Light Company (Indianapolis P&L)
26. Michigan Systems (Michigan Public Power Agency, Michigan South Central Power Agency, and Wolverine Power Supply Cooperative, Inc.) on behalf of themselves, Florida Municipal Power Agency, and Central Minnesota Municipal Power Agency (Michigan Systems)
27. Mid-Continent Area Power Pool (MAPP)
28. Montana-Dakota Utilities Company (Montana-Dakota Utilities)
29. Municipal Electric Utilities Association of New York State (NY MU)
30. National Rural Electric Cooperative Association (NRECA)
31. Nebraska Public Power District (NE Public Power District)
32. New York Power Pool (NYPP)
33. Northwest Regional Transmission Association (NWRTA)*
34. Nuclear Energy Institute (Nuclear Energy Institute)
35. Nucor Corporation (Nucor)
36. Ohio Valley Electric Corporation and Indiana-Kentucky Electric Corporation (Ohio Valley)
37. Pennsylvania Rural Electric Association and Allegheny Electric Cooperative, Inc. (PA Coops)
38. Public Service Company of Colorado (Public Service Co of CO)
39. Southern California Edison Company (SoCal Edison)
40. Southern California Gas Company (SoCal Gas) ''
41. Southwest Regional Transmission Association (SWRTA)*
42. Transmission Access Policy Study Group (TAPS)
43. Transmission Dependent Utility Systems (TDU Systems)
44. Union Electric Company (Union Electric)
45. Utilities for an Improved Transition (FIT Utilities)
46. Virginia Electric and Power Company (VEPCO)

*Request for rehearing raises no direct Order No. 889 issues.

**Request for clarification.

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federal register

Friday
March 14, 1997

Part III

Pension Benefit Guaranty Corporation

29 CFR Parts 4001 et al.

Termination of Single Employer Plans; Proposed Rule

Assessment of Penalties for Failure to Provide Required Information; Policy Statement

PENSION BENEFIT GUARANTY CORPORATION

29 CFR Parts 4001, 4006, 4041, 4050

RIN 1212–AA82

Termination of Single Employer Plans

AGENCY: Pension Benefit Guaranty Corporation.

ACTION: Proposed rule.

SUMMARY: In order to extend deadlines and otherwise to simplify the standard termination process, the Pension Benefit Guaranty Corporation is proposing amendments to its termination regulation. The amendments also require that plan administrators provide participants and beneficiaries with information on state guaranty association coverage.

DATES: Comments must be received on or before May 13, 1997.

ADDRESSES: Comments may be mailed to the Office of the General Counsel, Pension Benefit Guaranty Corporation, 1200 K Street NW., Washington, DC 20005–4026, or delivered to Suite 340 at the above address. Comments also may be sent by Internet e-mail to reg.comments@pbgc.gov. Comments will be available for public inspection at the PBGC's Communications and Public Affairs Department, Suite 240.

FOR FURTHER INFORMATION CONTACT: Harold J. Ashner, Assistant General Counsel, or Catherine B. Klion, Attorney, Office of the General Counsel, PBGC, 1200 K Street NW., Washington, DC 20005-4026, 202–326–4024 (202–326–4179 for TTY and TDD).

SUPPLEMENTARY INFORMATION:

Background

A single-employer plan covered by the PBGC's insurance program may be voluntarily terminated only in a standard or distress termination. The rules governing voluntary terminations are in section 4041 of the Employee Retirement Income Security Act of 1974 and part 4041 of the PBGC's regulations.

Once the decision is made to terminate a plan in a standard termination, the plan administrator must meet specific statutory and regulatory requirements. These requirements have caused difficulty for some plan administrators and participants. For example, a plan administrator who misses a deadline must restart the termination process, resulting in additional cost for the plan administrator and delayed distributions for participants.

The PBGC proposes to amend its regulations in order to extend certain deadlines and otherwise to simplify the termination process. The proposal was developed after conducting focus groups with plan practitioners and takes into account participant concerns and the PBGC's experience.

The amendment lessens the likelihood of errors, thereby reducing burdens on plan administrators and expediting distributions to participants. The amendment also implements a General Accounting Office recommendation that plan administrators provide information on state guaranty association coverage to participants, and makes a limited number of conforming changes to the distress termination and premium regulations, along with some conforming and simplifying changes to the missing participants regulations.

The major changes in the amendment are discussed below.

Standard Termination Process

Notice of intent to terminate: The amendment expands the notice to include information on state guaranty association coverage. The amendment also clarifies the language in the notice on freezing of benefit accruals to better coordinate with section 204(h) of ERISA. The PBGC's standard termination forms and instructions package will include a model notice of intent to terminate, along with state guaranty association coverage information.

Notice of plan benefits: The amendment simplifies and clarifies the information requirements.

Standard termination notice: The amendment extends the deadline for filing the standard termination notice with the PBGC from 120 days to 180 days after the proposed termination date. Upon review of the standard termination notice, the PBGC may require the submission of additional information relevant to the termination proceeding (e.g., where there is a question whether the plan is sufficient for all benefit liabilities). Such information will normally be due within 30 days after the date of the PBGC's request. The PBGC may shorten the time period where it determines that the interests of the PBGC or participants may be prejudiced by a delay in receipt of the information.

Close-out of plan: The amendment extends the close-out period for plan administrators that timely apply for an IRS determination letter from 60 to 120 days after receipt of a favorable letter, and eliminates the requirement that plan administrators notify the PBGC of the need for the extension.

In the case of benefits that must be provided in annuity form, the distribution must be made by purchasing irrevocable commitments from an insurer. In order to have a valid standard termination under Title IV of ERISA, the plan administrator must select the insurer in accordance with the fiduciary standards of Title I of ERISA (see Department of Labor Interpretive Bulletin 95–1, 60 FR 12328 (March 6, 1995)). The PBGC intends, as part of its standard termination audit program, to audit insurer selections for compliance with these standards and to take appropriate corrective action.

Post-distribution certification: The amendment provides that the PBGC will not assess a penalty if the post-distribution certification, which ERISA requires be filed within 30 days after the final distribution, is filed within 90 days after the distribution deadline. As discussed elsewhere in today's Federal Register, the PBGC is implementing this penalty policy immediately.

Extension of deadlines: The PBGC may in its discretion grant case-by-case extensions in narrow circumstances. The PBGC will grant an extension where it finds compelling reasons why it is not administratively feasible for the plan administrator (or other persons acting on behalf of the plan administrator) to take the action until the later date and the delay is brief. The PBGC will consider the length of the delay and whether ordinary business care and prudence in attempting to meet the deadline is exercised.

PBGC discretion not to nullify: The amendment also incorporates section 778(a) of the Retirement Protection Act of 1994, which gives the PBGC discretion not to nullify defective standard terminations in certain circumstances if it determines that nullification ''would be inconsistent with the interests of participants and beneficiaries.''

Distress Termination Process

A plan that is sufficient for at least guaranteed benefits closes out under procedures that parallel those used in a standard termination. The amendment makes conforming changes to the distress termination procedures, primarily with respect to the rules that apply after the PBGC issues a distribution notice authorizing a plan to close out in the private sector. The time limits governing the initial processing of a distress termination are not changed. The PBGC may address other distress termination issues in a separate rulemaking.

General Provisions

Filing rules: The amendment changes the date of filing a notice with the PBGC from the date of receipt to the date of mailing with the United States Postal Service (as evidenced by a postmark) or deposit with a commercial delivery service (provided the notice is received by the PBGC within two regular business days). The amendment also allows electronic filing with the PBGC and, in certain circumstances, electronic issuance to third parties.

Maintenance of plan records. The amendment clarifies that, while the plan administrator and each contributing sponsor of a terminating plan are subject to the requirement to maintain records used to compute benefits, if any one of them complies with that requirement, the others need not comply.

Post-termination amendments: The amendment provides that, except to the extent necessary to meet a qualification requirement under section 401 of the Code, a plan amendment adopted or effective after a plan's termination date is disregarded with respect to a participant or beneficiary to the extent the amendment (1) decreases the amount or value of the participant's or beneficiary's benefits (*e.g.,* by adopting less favorable assumptions for calculating a lump sum distribution or by eliminating an ancillary benefit such as a Social Security supplement under section 204(b)(1)(G) of ERISA), or (2) eliminates or restricts an optional form of benefit for the participant or beneficiary.

Missing Participants: The amendment provides that the diligent search procedures for a missing participant whose designated benefit is paid to the PBGC also apply for a missing participant for whom the plan administrator purchases an annuity. The amendment requires plan administrators who purchase an annuity for a missing participant to provide the PBGC with the amount of the participant's normal retirement benefit (to the extent that information is known). This information will facilitate the PBGC's ability to respond to participant inquiries and to target its search efforts.

The amendment eliminates detailed rules that apply in the unusual circumstance of an individual located or discovered to be missing late in the distribution process. The PBGC can more effectively deal with such situations by granting discretionary extensions as appropriate on a case-by-case basis in order to ensure that adequate time is available.

The amendment also provides penalty relief for the late filing of certain information about missing participants comparable to that provided for late post-distribution certifications.

Effective Date

While the changes will generally apply to new terminations initiated on or after the effective date of the final rule, the PBGC intends to allow plan administrators to apply certain portions of the final rule to terminations in process.

Paperwork Reduction Act

The information requirements contained in this proposed rule have been submitted to the Office of Management and Budget for review under the Paperwork Reduction Act of 1995, with a request for a three-year approval. As part of this request, the PBGC has made clarifying and other changes (related to the proposed rule) to its implementing forms and instructions under its regulations on termination of single-employer plans and missing participants. Copies of the PBGC's request may be obtained free of charge by writing to the PBGC Communications and Public Affairs Department, suite 240, 1200 K Street, NW., Washington, DC 20005, or by visiting that office between the hours of 9 a.m. and 4 p.m.

The PBGC needs the information required to be submitted to ensure that a voluntary termination is completed in accordance with statutory and regulatory requirements and to facilitate the payment of benefits to missing participants. Participants need the information required to be disclosed so that they will be informed about the status of the proposed termination of their plan and about their benefits upon termination.

Much of the work associated with terminating a plan is performed for purposes other than meeting the collection of information requirements in the PBGC's termination and missing participants regulations. The PBGC estimates that 3,640 plan administrators will be subject to these requirements each year, and that the total annual burden of complying with these requirements is 4,983 hours and $3,139,560.

Comments on the paperwork provisions under this proposed rule should be mailed to the Office of Information and Regulatory Affairs, Office of Management and Budget, Attention: Desk Officer for the Pension Benefit Guaranty Corporation, Washington, DC 20503. Comments may address (among other things)—

- Whether the proposed collection of information is needed for the proper performance of the PBGC's functions and will have practical utility;
- The accuracy of the PBGC's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;
- Enhancement of the quality, utility, and clarity of the information to be collected; and
- Minimizing 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 submission of responses.

The PBGC already allows electronic submission of participant and beneficiary data in a distress termination and has been actively considering whether to allow other information to be provided electronically. In certain circumstances, this proposed rule allows electronic filing with the PBGC and electronic issuance of notices to third parties. The PBGC welcomes comments on electronic filing and issuance requirements, particularly on how to ensure that notices issued electronically to third parties are actually received by the persons entitled to receive them.

The PBGC also invites comments on whether, given the PBGC's limited role in standard terminations, the burden of the standard termination filing process could be further reduced.

Compliance With Rulemaking Guidelines

The PBGC has determined that this action is not a ''significant regulatory action'' under the criteria set forth in Executive Order 12866.

The PBGC certifies under section 605(b) of the Regulatory Flexibility Act that this rule will not have a significant economic impact on a substantial number of small entities. While this rule simplifies procedures and extends deadlines, the actions required to terminate a plan are essentially unchanged. Accordingly, sections 603 and 604 of the Regulatory Flexibility Act do not apply.

List of Subjects

29 CFR Part 4001

Pension insurance, Pensions, Reporting and recordkeeping requirements.

29 CFR Part 4006

Penalties, Pension insurance, Pensions, Reporting and recordkeeping requirements.

29 CFR Part 4041

Pension insurance, Pensions, Reporting and recordkeeping requirements.

29 CFR Part 4050

Pensions, Reporting and recordkeeping requirements.

For the reasons set forth above, the PBGC proposes to amend parts 4001, 4006, 4041, and 4050 of 29 CFR chapter LX as follows.

PART 4041—TERMINATION OF SINGLE-EMPLOYER PLANS

1. The authority citation for Part 4041 continues to read as follows:

Authority: 29 U.S.C. 1302(b)(3), 1341, 1344, 1350.

§§ 4041.46 and 4041.48 [Removed]

2. Section 4041.46 is removed.

§ 4041.47 and §§ 4041.41 Through 4041.45 [Redesignated as §§ 4041.49 and 4041.43 through 4041.47]

3. § 4041.47 is redesignated as § 4041.49; and §§ 4041.41 through 4041.45 are redesignated as §§ 4041.43 through 4041.47.

§ 4041.3 [Amended and Redesignated as § 4041.41]

4. In § 4041.3, the section heading is amended by removing the words ‘‘a standard termination or’’; paragraphs (a) and (b) are removed; paragraphs (c) through (g) are redesignated as paragraphs (a) through (e); and as so amended, § 4041.3 is redesignated as § 4041.41. (Redesignated § 4041.41 is the first section under Subpart C.)

§ 4041.4 [Amended and Redesignated]

5. In 4041.4, paragraphs (b), (d) and (e) are removed; paragraphs (c) and (f) through (h) are redesignated as paragraphs (b) through (e); and as so amended, § 4041.4 is redesignated as § 4041.42.

Subparts A and B [Amended]

6. Subparts A and B of Part 4041 are revised to read as follows:

PART 4041—TERMINATION OF SINGLE-EMPLOYER PLANS

Subpart A—General Provisions

Sec.

4041.1 Purpose and scope.
4041.2 Definitions.
4041.3 Computation of time; filing and issuance rules.
4041.4 Disaster relief.
4041.5 Maintenance of plan records.
4041.6 Effect of failure to provide required information.
4041.7 Collective bargaining agreement challenges.
4041.8 Post-termination amendments.

Subpart B—Standard Termination Process

4041.21 Requirements for a standard termination.
4041.22 Administration of plan during termination process.
4041.23 Notice of intent to terminate.
4041.24 Notices of plan benefits.
4041.25 Standard termination notice.
4041.26 PBGC review of standard termination notice.
4041.27 Notice of annuity information.
4041.28 Closeout of plan.
4041.29 Post-distribution certification.
4041.30 Requests for deadline extensions.
4041.31 Notice of noncompliance.

Subpart A—General Provisions.

§ 4041.1 Purpose and scope.

This part sets forth the rules and procedures for terminating a single-employer plan in a standard or distress termination under section 4041 of ERISA, the exclusive means of voluntarily terminating a plan.

§ 4041.2 Definitions.

The following terms are defined in § 4001.2 of this chapter: affected party, annuity, benefit liabilities, Code, contributing sponsor, controlled group, distress termination, distribution date, EIN, employer, ERISA, guaranteed benefit, insurer, irrevocable commitment, IRS, mandatory employee contributions, normal retirement age, notice of intent to terminate, PBGC, person, plan administrator, plan year, PN, single-employer plan, standard termination, termination date, and title IV benefit. In addition, for purposes of this part:

Distress termination notice means the notice filed with the PBGC pursuant to § 4041.45.

Distribution notice means the notice issued to the plan administrator by the PBGC pursuant to § 4041.47(c) upon the PBGC's determination that the plan has sufficient assets to pay at least guaranteed benefits.

Majority owner means an individual who owns, directly or indirectly, 50 percent or more (taking into account the constructive ownership rules of section 414 (b) and (c) of the Code) of—

(1) An unincorporated trade or business;

(2) The capital interest or the profits interest in a partnership; or

(3) Either the voting stock of a corporation or the value of all of the stock of a corporation.

Notice of noncompliance means a notice issued to a plan administrator by the PBGC pursuant to § 4041.31 advising the plan administrator that the requirements for a standard termination have not been satisfied and that the plan is an ongoing plan.

Notice of plan benefits means the notice to each participant and beneficiary required by § 4041.24.

Participant means—

(1) Any individual who is currently in employment covered by the plan and who is earning or retaining credited service under the plan, including any individual who is considered covered under the plan for purposes of meeting the minimum participation requirements but who, because of offset or similar provisions, does not have any accrued benefits;

(2) Any nonvested individual who is not currently in employment covered by the plan but who is earning or retaining credited service under the plan; and

(3) Any individual who is retired or separated from employment covered by the plan and who is receiving benefits under the plan or is entitled to begin receiving benefits under the plan in the future, excluding any such individual to whom an insurer has made an irrevocable commitment to pay all the benefits to which the individual is entitled under the plan.

Plan benefits means the benefits to which a participant is, or may become, entitled under the plan's provisions in effect as of the termination date, based on the participant's benefit under the plan as of that date. Each participant's ‘‘plan benefits’’ equals that participant's ‘‘benefit liabilities,’’ and the sum of all ‘‘plan benefits’’ equals the plan's ‘‘benefit liabilities.’’

Proposed termination date means the date specified as such by the plan administrator in the notice of intent to terminate or, if later, in the standard or distress termination notice.

Residual assets means the plan assets remaining after all benefit liabilities and other liabilities (*e.g.*, PBGC premiums) of the plan have been satisfied.

Standard termination notice means the notice filed with the PBGC pursuant to § 4041.25.

State guaranty association means an association of insurers created by a State, the District of Columbia, or the Commonwealth of Puerto Rico to pay benefits and to continue coverage, within statutory limits, under life and health insurance policies and annuity contracts when an insurer fails.

§ 4041.3 Computation of time; filing and issuance rules.

(a) *Computation of time.* In computing any period of time under this part, the day of the event from which the period begins is not counted. The last day of the period is included. If the last day falls on a Saturday, Sunday, or Federal holiday, the period runs until the end of the next regular business day. A proposed termination date may be any day, including a Saturday, Sunday, or Federal holiday.

(b) *Filing with the PBGC.*

(1) *Method of filing.* Any document to be filed under this part shall be delivered to the PBGC in accordance with the applicable PBGC termination forms and instructions package.

(2) *Date of filing.* Any information required or permitted to be filed with the PBGC shall be deemed filed—

(i) On the date of the United States postmark, if the postmark was made by the United States Postal Service and the document was mailed postage prepaid to the PBGC;

(ii) On the date it is deposited for delivery to the PBGC with a commercial delivery service, provided it is received by the PBGC within two regular business days; or

(iii) Except as provided in paragraphs (b)(2)(i) or (b)(2)(ii), on the date it is received by the PBGC. Information received on a weekend or Federal holiday or after 5:00 p.m. on a weekday is considered filed on the next regular business day.

(c) *Issuance to other parties.* The following rules apply to affected parties (other than the PBGC). For purposes of this paragraph (c), a person entitled to notice under the spin-off/termination transaction rules of §§ 4041.23(c) or 4041.24(f) is treated as an affected party.

(1) *Permissible methods of issuance.* The plan administrator shall issue any notice to an affected party individually—

(i) By hand delivery;

(ii) By first-class mail or commercial delivery service to the affected party's last known address; or

(iii) By electronic means reasonably calculated to ensure actual receipt by the affected party.

(2) *Date of issuance.* Any notice is deemed issued to an affected party on the date on which it is—

(i) Handed to the affected party;

(ii) Deposited with the mail or a commercial delivery service (as evidenced by a postmark or written receipt); or

(iii) Transmitted electronically to the affected party.

(3) *Omission of affected parties.* The failure to issue any notice to an affected party (other than any employee organization) within the specified time period will not cause the notice to be untimely if—

(i) *After-discovered affected parties.* The plan administrator could not reasonably have been expected to know of the affected party, and issues the notice promptly after discovering the affected party; or

(ii) *De minimis administrative errors.* The failure was due to administrative error involving only a *de minimis* percentage of affected parties, and the plan administrator issues the notice to each such affected party promptly after discovering the error.

(4) *Form of notices to affected parties.* All notices to affected parties shall be readable and written in a manner calculated to be understood by the average plan participant.

(5) *Foreign languages.* The plan administrator of a plan that (as of the proposed termination date) covers the numbers or percentages in § 2520.104b-10(e) of this title of participants literate only in the same non-English language shall, for any notice to affected parties—

(i) Include a prominent legend in that common non-English language advising them how to obtain assistance in understanding the notice; or

(ii) Provide the notice in that common non-English language to those affected parties literate only in that language.

§ 4041.4 Disaster relief.

When the President of the United States declares that, under the Disaster Relief Act (42 U.S.C. 5121, 5122(2), 5141(b)), a major disaster exists, the Executive Director of the PBGC (or his or her designee) may, by issuing one or more notices of disaster relief, extend by up to 180 days any due date under this part.

§ 4041.5 Maintenance of plan records.

(a) *Retention requirement.*

(1) *Persons subject to requirement.* Each contributing sponsor and the plan administrator of a plan terminating in a standard termination, or in a distress termination that closes out in accordance with § 4041.50, shall maintain all records used to compute benefits with respect to each individual who is a plan participant or a beneficiary of a deceased participant as of the termination date. If a contributing sponsor or the plan administrator complies with part or all of the requirements of this paragraph (a), the other(s) need not comply with respect to such information.

(2) *Retention period.* The records described in paragraph (a)(1) shall be preserved for six years after the date when the post-distribution certification under this part is filed with the PBGC.

(b) *Availability of records.* The contributing sponsor or plan administrator shall make records related to the termination available to the PBGC upon request for inspection and photocopying, and shall submit such records to the PBGC within 30 days after the date of a written request by the PBGC or by a later date specified therein.

§ 4041.6 Effect of failure to provide required information.

If a plan administrator fails to provide any information required under this part within the specified time limit, the PBGC may assess a penalty under section 4071 of ERISA of up to $1,000 a day for each day that the failure continues. The PBGC may also pursue any other equitable or legal remedies available to it under the law, including, if appropriate, the issuance of a notice of noncompliance under § 4041.31.

§ 4041.7 Challenges to plan termination under collective bargaining agreement.

(a) *Suspension upon formal challenge to termination.*

(1) *Notice of formal challenge.*

(i) If the PBGC is advised, before its review period under § 4041.26(a) ends, or before issuance of a notice of inability to determine sufficiency or a distribution notice under § 4041.47 (b) or (c), that a formal challenge to the termination has been initiated as described in paragraph (c), the PBGC shall suspend the termination proceeding and so advise the plan administrator in writing.

(ii) If the PBGC is advised of a challenge described in paragraph (a)(1)(i) of this section after the time specified therein, the PBGC may suspend the termination proceeding and shall so advise the plan administrator in writing.

(2) *Standard terminations.* During any period of suspension in a standard termination—

(i) The running of all time periods specified in ERISA or this part relevant to the termination shall be suspended; and

(ii) The plan administrator shall comply with the prohibitions in § 4041.22.

(3) *Distress terminations.* During any period of suspension in a distress termination—

(i) The issuance by the PBGC of any notice of inability to determine sufficiency or distribution notice shall be stayed or, if any such notice was previously issued, its effectiveness shall be stayed;

(ii) The plan administrator shall comply with the prohibitions in § 4041.42; and

(iii) The plan administrator shall file a distress termination notice with the PBGC pursuant to § 4041.45.

(b) *Existing collective bargaining agreement.* For purposes of this section, an existing collective bargaining agreement means a collective bargaining agreement that has not been made inoperative by a judicial ruling and, by its terms, either has not expired or is extended beyond its stated expiration date because neither of the collective bargaining parties took the required action to terminate it. When a collective bargaining agreement no longer meets these conditions, it ceases to be an ''existing collective bargaining agreement,'' whether or not any or all of its terms may continue to apply by operation of law.

(c) *Formal challenge to termination.* A formal challenge to a plan termination asserting that the termination would violate the terms and conditions of an existing collective bargaining agreement is initiated when—

(1) Any procedure specified in the collective bargaining agreement for resolving disputes under the agreement commences; or

(2) Any action before an arbitrator, administrative agency or board, or court under applicable labor-management relations law commences.

(d) *Resolution of challenge.* Immediately upon the final resolution of the challenge, the plan administrator shall notify the PBGC in writing of the outcome of the challenge, provide the PBGC with a copy of any award or order, and, if the validity of the proposed termination has been upheld, advise the PBGC whether the proposed termination is to proceed. The final resolution ends the suspension period under paragraph (a) of this section.

(1) *Challenge sustained.* If the final resolution is that the proposed termination violates an existing collective bargaining agreement, the PBGC shall dismiss the termination proceeding, all actions taken to effect the plan termination shall be null and void, and the plan shall be an ongoing plan. In this event, in a distress termination, § 4041.42(d) shall apply as of the date of the dismissal by the PBGC.

(2) *Termination sustained.* If the final resolution is that the proposed termination does not violate an existing collective bargaining agreement and the plan administrator has notified the PBGC that the termination is to proceed, the PBGC shall reactivate the termination proceeding by sending a written notice thereof to the plan administrator, and—

(i) The termination proceeding shall continue from the point where it was suspended;

(ii) All actions taken to effect the termination before the suspension shall be effective;

(iii) Any time periods that were suspended shall resume running from the date of the PBGC's notice of the reactivation of the proceeding;

(iv) Any time periods that had fewer than 15 days remaining shall be extended to the 15th day after the date of the PBGC's notice, or such later date as the PBGC may specify; and

(v) In a distress termination, the PBGC shall proceed to issue a notice of inability to determine sufficiency or a distribution notice (or reactivate any such notice stayed under paragraph (a)(3) of this section), either with or without first requesting updated information from the plan administrator pursuant to § 4041.45(c).

(e) *Final resolution of challenge.* A formal challenge to a proposed termination is finally resolved when—

(1) The parties involved in the challenge enter into a settlement that resolves the challenge;

(2) A final award, administrative decision, or court order is issued that is not subject to review or appeal; or

(3) A final award, administrative decision, or court order is issued that is not appealed, or review or enforcement of which is not sought, within the time for filing an appeal or requesting review or enforcement.

(f) *Involuntary termination by the PBGC.* Notwithstanding any other provision of this section, the PBGC retains the authority in any case to initiate a plan termination in accordance with the provisions of section 4042 of ERISA.

§ 4041.8 Post-termination amendments.

Except to the extent necessary to meet a qualification requirement under section 401 of the Code, a plan amendment that is adopted or effective after a plan's termination date shall be disregarded with respect to a participant or beneficiary to the extent the amendment—

(a) Decreases the amount or value of the participant's or beneficiary's benefits (*e.g.,* by adopting less favorable assumptions for calculating a lump sum distribution or by eliminating an ancillary benefit such as a Social Security supplement under section 204(b)(1)(G) of ERISA); or

(b) Eliminates or restricts an optional form of benefit for the participant or beneficiary.

Subpart B—Standard Termination Process

§ 4041.21 Requirements for a standard termination.

(a) *Notice and distribution requirements.* A standard termination is valid if the plan administrator—

(1) Issues a notice of intent to terminate to all affected parties (other than the PBGC) in accordance with § 4041.23;

(2) Issues notices of plan benefits to all affected parties entitled to plan benefits in accordance with § 4041.24;

(3) Files a standard termination notice with the PBGC in accordance with § 4041.25;

(4) Distributes the plan's assets in satisfaction of all of the plan's benefit liabilities in accordance with § 4041.28(a); and

(5) In the case of a spin-off/termination transaction (as defined in § 4041.23(c)), provides the notices required by § 4041.23(c), § 4041.24(f), and § 4041.27(a)(2).

(b) *Plan sufficiency.*

(1) *Commitment to make plan sufficient.* A contributing sponsor of a plan or any other member of the plan's controlled group may make a commitment to contribute any additional sums necessary to enable the plan to satisfy benefit liabilities in accordance with § 4041.28(a). A commitment shall be valid only if—

(i) It is made to the plan;

(ii) It is in writing, signed by the contributing sponsor or controlled group member(s); and

(iii) In any case in which the person making the commitment is the subject of a bankruptcy liquidation or reorganization proceeding, as described in § 4041.41(c) (1) or (c)(2), the commitment is approved by the court before which the liquidation or reorganization proceeding is pending or a person not in bankruptcy unconditionally guarantees to meet the commitment at or before the time distribution of assets is required.

(2) *Alternative treatment of majority owner's benefit.* A majority owner may elect to forego receipt of his or her benefit to the extent necessary to enable the plan to satisfy all other benefit liabilities in accordance with § 4041.28(a). Any such alternative treatment of the majority owner's benefit is valid only if—

(i) The election is in writing;

(ii) In any case in which section 205(g) of ERISA requires spousal consent to the majority owner's receipt of his or her benefit in a form other than a qualified joint and survivor annuity, the spouse of the majority owner consents in accordance with such section; and

(iii) The majority owner's election is not inconsistent with a qualified domestic relations order (as defined in section 206(d)(3) of ERISA).

§ 4041.22 Administration of plan during pendency of termination process.

(a) *In general.* A plan administrator may distribute plan assets in connection with the termination of the plan only in accordance with the provisions of this part. From the first day the plan administrator issues a notice of intent to terminate to the last day of the PBGC's review period under § 4041.26(a), the plan administrator shall continue to carry out the normal operations of the plan. During that time period, except as provided in paragraph (b), the plan administrator shall not—

(1) Purchase irrevocable commitments to provide any plan benefits; or

(2) Pay benefits attributable to employer contributions, other than death benefits, in any form other than an annuity.

(b) *Exception.* The plan administrator may pay benefits attributable to employer contributions either through the purchase of irrevocable commitments or in a form other than an annuity if—

(1) The participant has separated from active employment;

(2) The distribution is consistent with prior plan practice; and

(3) The distribution is not reasonably expected to jeopardize the plan's sufficiency for benefit liabilities.

§ 4041.23 Notice of intent to terminate.

(a) *Notice requirement.*

(1) *In general.* At least 60 days and no more than 90 days before the proposed termination date, the plan administrator shall issue a notice of intent to terminate to each person (other than the PBGC) that is, as of the proposed termination date, an affected party. (The PBGC's standard termination forms and instructions package includes a model notice of intent to terminate.)

(2) *Early issuance of NOIT.* The PBGC may consider a notice of intent to terminate to be timely under paragraph (a)(1) if the notice was early by a *de minimis* number of days and the PBGC finds that the early issuance was the result of administrative error.

(b) *Contents of notice.* The notice of intent to terminate shall include—

(1) *Identifying information.* The name and PN of the plan, the name and EIN of each contributing sponsor, and the name, address, and telephone number of the person who may be contacted by an affected party with questions concerning the plan's termination;

(2) *Intent to terminate plan.* A statement that the plan administrator intends to terminate the plan in a standard termination as of a specified proposed termination date and will notify the affected party if the proposed termination date is changed to a later date or if the termination does not occur;

(3) *Sufficiency requirement.* A statement that, in order to terminate in a standard termination, plan assets must be sufficient to provide all benefit liabilities under the plan;

(4) *Cessation of accruals.* A statement (as applicable) informing affected parties that—

(i) Benefit accruals will cease as of the termination date, but will continue if the plan does not terminate;

(ii) A plan amendment has been adopted under which benefit accruals will cease, in accordance with section 204(h) of ERISA, as of the proposed termination date or a specified date before the proposed termination date, whether or not the plan is terminated; or

(iii) Benefit accruals ceased, in accordance with section 204(h) of ERISA, as of a specified date before the notice of intent to terminate was issued;

(5) *Annuity information.* If required under § 4041.27, the annuity information described therein;

(6) *Benefit information.* A statement that each affected party entitled to plan benefits will receive a written notification regarding his or her benefits;

(7) *Continuation of monthly benefits.* For those persons who are (as of the proposed termination date) in pay status, a statement that their monthly (or other periodic) benefit amounts will not be affected by the plan's termination; and

(8) *Extinguishment of guarantee.* A statement that after plan assets have been distributed in full satisfaction of all pension benefits under the plan with respect to a participant or a beneficiary of a deceased participant, either by the purchase of irrevocable commitments (annuity contracts) or by an alternative form of distribution provided for under the plan, the PBGC no longer guarantees that participant's or beneficiary's plan benefits.

(c) *Spin-off/termination transactions.* In the case of a transaction in which a single defined benefit plan is split into two or more plans and there is a reversion of residual assets to an employer upon the termination of one or more but fewer than all of the resulting plans (a ''spin-off/termination transaction''), the plan administrator shall, within the time period specified in paragraph (a), provide all participants, beneficiaries of deceased participants, and alternate payees in the original plan who are (as of the proposed termination date) covered by an ongoing plan with a notice describing the transaction.

§ 4041.24 Notices of plan benefits.

(a) *Notice requirement.* The plan administrator shall, no later than the time the plan administrator files the standard termination notice with the PBGC, issue a notice of plan benefits to each person (other than the PBGC and any employee organization) who is, as of the proposed termination date, an affected party.

(b) *Contents of notice.* The plan administrator shall include in each notice of plan benefits—

(1) The name and PN of the plan, the name and EIN of each contributing sponsor, and the name, address, and telephone number of an individual who may be contacted to answer questions concerning a benefit;

(2) The proposed termination date given in the notice of intent to terminate and any extended proposed termination date under § 4041.25(b);

(3) If the amount of the plan benefits set forth in the notice is an estimate, a statement that the amount is an estimate and that benefits paid may be greater than or less than the estimate;

(4) Except in the case of an affected party in pay status for more than one year as of the proposed termination date—

(i) The personal data used to calculate the affected party's plan benefits; and

(ii) A statement requesting that the affected party review the personal data and notify the plan administrator of any incorrect data; and

(5) The information in paragraph (c), (d), or (e), as applicable.

(c) *Benefits of persons in pay status.* For an affected party in pay status as of the proposed termination date, the plan administrator shall include in the notice of plan benefits—

(1) The amount and form of the participant's or beneficiary's plan benefits payable as of the proposed termination date;

(2) The amount and form of benefit, if any, payable to a beneficiary upon the participant's death and the name of the beneficiary; and

(3) The amount and date of any increase or decrease in the benefit scheduled to occur (or that has already occurred) after the proposed termination date and an explanation of the increase or decrease, including, where applicable, a reference to the pertinent plan provision.

(d) *Benefits of persons with valid elections or de minimis benefits.* For an affected party who is not in pay status as of the proposed termination date, but who has, as of that date, validly elected a form and starting date, or with respect to whom the plan administrator has determined that a nonconsensual lump sum distribution will be made, the plan administrator shall include in the notice of plan benefits—

(1) The amount and form of the person's plan benefits payable as of the projected benefit starting date, and what that date is;

(2) The information in paragraphs (c)(2) and (c)(3);

(3) If the plan benefits will be paid in any form other than a lump sum and the age at which, or form in which, the plan benefits will be paid differs from the normal retirement benefit—

(i) The age or form stated in the plan; and

(ii) The age or form adjustment factors; and

(4) If the plan benefits will be paid in a lump sum—

(i) An explanation of when a lump sum may be paid without the consent of the participant or the participant's spouse;

(ii) The interest rate used to convert to the lump sum benefit and a reference to the pertinent plan provisions;

(iii) An explanation of how the interest rate is used to calculate the lump sum;

(iv) A statement that the use of a higher interest rate results in a smaller lump sum amount; and

(v) A statement that the applicable interest rate may change before the distribution date.

(e) *Benefits of all other persons not in pay status.* For any other affected party not described in paragraph (c) or (d), the plan administrator shall include in the notice of plan benefits—

(1) The amount and form of the person's plan benefits payable at normal retirement age in any form permitted under the plan;

(2) Any alternative benefit forms, including those payable to a beneficiary upon the person's death either before or after benefits commence;

(3) If the person is or may become entitled to a benefit that would be payable before normal retirement age, the amount and form of benefit that would be payable at the earliest benefit commencement date (or, if more than one such form is payable at the earliest benefit commencement date, any one of those forms) and whether the benefit commencing on such date would be subject to future reduction; and

(4) If the plan benefits may be paid in a lump sum, the information in paragraph (d)(4).

(f) *Spin-off/termination transactions.* In the case of a spin-off/termination transaction (as defined in § 4041.23(c)), the plan administrator shall, no later than the time the plan administrator files the standard termination notice for any terminating plan, provide all participants, beneficiaries of deceased participants, and alternate payees in the original plan who are (as of the proposed termination date) covered by an ongoing plan with a notice of plan benefits containing the information in paragraphs (b) through (e).

§ 4041.25 Standard termination notice.

(a) *Notice requirement.* The plan administrator shall file with the PBGC a standard termination notice, consisting of the PBGC Form 500, completed in accordance with the instructions thereto, on or before the 180th day after the proposed termination date.

(b) *Change of proposed termination date.* The plan administrator may, in the standard termination notice, select a proposed termination date that is later than the date specified in the notice of intent to terminate, provided it is not later than 90 days after the earliest date on which a notice of intent to terminate was issued to any affected party.

(c) *Request for IRS determination letter.* To qualify for the distribution deadline in § 4041.28(a)(1)(ii), the plan administrator shall submit to the IRS a valid request for a determination of the plan's qualification status upon termination (''determination letter'') by the time the standard termination notice is filed.

§ 4041.26 PBGC review of standard termination notice.

(a) *Review period.*

(1) *In general.* The PBGC shall notify the plan administrator in writing of the date on which it received a complete standard termination notice at the address provided in the PBGC's standard termination forms and instructions package. If the PBGC does not issue a notice of noncompliance during its 60-day review period following such date, the plan administrator shall proceed to close out the plan in accordance with § 4041.28.

(2) *Extension of review period.* The PBGC and the plan administrator may, before the expiration of the PBGC review period in paragraph (a)(1), agree in writing to extend that period.

(b) *If standard termination notice is incomplete.*

(1) *For purposes of timely filing.* If the standard termination notice is incomplete, the PBGC may, based on the nature and extent of the omission, provide the plan administrator an opportunity to complete the notice. In such a case, the standard termination notice shall be deemed to have been complete as of the date when originally filed for purposes of § 4041.25(a), provided the plan administrator provides the missing information by the later of—

(i) The 180th day after the proposed termination date; or

(ii) The 30th day after the date of the PBGC notice that the filing was incomplete.

(2) *For purposes of PBGC review period.* If the standard termination notice is completed under paragraph (b)(1), the PBGC shall determine whether the notice shall be deemed to have been complete as of the date when originally filed for purposes of determining when the PBGC's review period begins under § 4041.26(a)(1).

(c) *Additional information.*

(1) *Deadline for providing additional information.* The PBGC may in any case require the submission of additional information relevant to the termination proceeding. Any such additional information becomes part of the standard termination notice and shall be submitted within 30 days after the date of a written request by the PBGC, or within a different time period specified therein. The PBGC may in its discretion shorten the time period where it determines that the interests of the PBGC or participants may be prejudiced by a delay in receipt of the information.

(2) *Effect on termination proceeding.* A request for additional information shall suspend the running of the PBGC's 60-day review period. The review period shall begin running again on the day the required information is received and continue for the greater of—

(i) The number of days remaining in the review period; or

(ii) Five regular business days.

§ 4041.27 Notice of annuity information.

(a) *Notice requirement.*

(1) *In general.* The plan administrator shall provide notices in accordance with this section to each affected party other than—

(i) An affected party whose plan benefits will be distributed in the form of a nonconsensual lump sum; and

(ii) The PBGC.

(2) *Spin-off/termination transactions.* The plan administrator shall provide the information in paragraph (d) to a person entitled to notice under §§ 4041.23(c) or 4041.24(f), at the same time and in the same manner as required for an affected party other than the PBGC.

(b) *Content of notice.* The plan administrator shall include, as part of the notice of intent to terminate—

(1) *Identity of insurers.* The name and address of the insurer or insurers from whom (if known), or (if not) from among whom, the plan administrator intends to purchase irrevocable commitments (annuity contracts);

(2) *Change in identity of insurers.* A statement that if the plan administrator later decides to select a different insurer, affected parties will receive a supplemental notice no later than 45 days before the distribution date; and

(3) *State guaranty association coverage information.* The information on state guaranty association coverage of annuities described in paragraphs (a)(3) (i) and (ii) of this section:

(i) The following notice:

Under your pension plan, your benefits may be paid in the form of an annuity purchased from a licensed insurance company. If we purchase an annuity for you to provide all your pension benefits under the plan, the insurance company will be responsible for paying your benefits.

All states, the District of Columbia, and the Commonwealth of Puerto Rico have established ''guaranty associations'' to protect policyholders in the event of an insurance company's financial failure. All insurance companies licensed to sell insurance in a state are required to be members of that state's guaranty association. If a member insurance company fails, the association collects money from the other member insurance companies to continue coverage up to statutory limits, as specified by law, for its policyholders.

State guaranty association coverage of your annuity means that the guaranty association may pay part or all of your annuity if the insurance company responsible for the annuity cannot pay. How much of your annuity the fund would pay, if any, may depend on factors such as the amount of your annuity, the state in which you reside at the time the insurance company fails to pay, and the state in which the insurance company is located. Since state laws vary, you will need to see what the law in your state says at the relevant time.

State guaranty association coverage is limited by statute in total dollar amount. In most states, the maximum amount of annuity coverage is stated in terms of the present value of the annuity. The maximum amount and how it is stated varies from state to state and may change over time.

This notice is intended to help you understand the general nature of state guaranty association protection of the annuity you may receive. It is only a summary. Listings of state guaranty associations and their addresses and telephone numbers, and of their general coverage limits are attached.

(ii) Listings of the addresses and telephone numbers of the state guaranty association offices in all 50 states, the District of Columbia, and the Commonwealth of Puerto Rico, and of the dollar coverage limitations applicable to each state, along with the date as of which the listings were prepared. The plan administrator shall use listings that are at least as current as those included as sample listings in the standard termination forms and instructions package applicable to the plan termination proceeding.

(c) *Where insurer(s) not known.*

(1) *Extension of deadline for notice.* If the identity-of-insurer information in paragraph (b)(1) is not known at the time the plan administrator is required to provide it to an affected party as part of a notice of intent to terminate, the plan administrator shall instead provide it in a supplemental notice under paragraph (d).

(2) *Alternative NOIT information.* A plan administrator that qualifies for the extension in paragraph (c)(1) with respect to a notice of intent to terminate shall include therein (in lieu of the information in paragraph (b)) a statement that—

(i) Irrevocable commitments (annuity contracts) may be purchased from an insurer to provide some or all of the benefits under the plan;

(ii) The insurer or insurers have not yet been identified; and

(iii) Affected parties will be notified at a later date (but no later than 45 days before the distribution date) of the name and address of the insurer or insurers from whom (if known), or (if not) from among whom, the plan administrator intends to purchase irrevocable commitments (annuity contracts).

(d) *Supplemental notice.* The plan administrator shall provide a supplemental notice to an affected party in accordance with this paragraph (d) if the plan administrator did not previously notify the affected party of the identity of insurer(s) or, after having previously notified the affected party of the identity of insurer(s), decides to select a different insurer. A failure to provide a required supplemental notice to an affected party shall be deemed to be a failure to comply with the notice of intent to terminate requirements.

(1) *Deadline for supplemental notice.* The deadline for issuing the supplemental notice is 45 days before the affected party's distribution date (or, in the case of an employee organization, 45 days before the earliest distribution date for any affected party that it represents).

(2) *Content of supplemental notice.* The supplemental notice shall include—

(i) The identity-of-insurer information in paragraph (b)(1);

(ii) The information regarding change of identity of insurer(s) in paragraph (b)(2); and

(iii) Unless the state guaranty association coverage information in paragraph (b)(3) was previously provided to the affected party, such information and the extinguishment-of-guarantee information in § 4041.23(b)(8).

§ 4041.28 Closeout of plan.

(a) *Distribution deadline.*

(1) *In general.* Unless a notice of noncompliance is issued under § 4041.31(a), the plan administrator shall complete the distribution of plan assets in accordance with paragraph (c) by the later of—

(i) 180 days after the expiration of the PBGC's 60-day (or extended) review period under § 4041.26(a); or

(ii) If the plan administrator meets the requirements of § 4041.25(c), 120 days after receipt of a favorable determination from the IRS.

(2) *Revocation of notice of noncompliance.* If the PBGC revokes a notice of noncompliance issued under § 4041.31(a), the distribution deadline is extended until the 180th day after the date of the revocation.

(b) *Assets insufficient to satisfy benefit liabilities.* If the plan administrator determines that plan assets are not sufficient to satisfy all benefit liabilities at the time of any distribution (with assets determined net of other liabilities, including PBGC premiums), the plan administrator shall not make any further distribution of assets to effect the plan's termination and shall promptly notify the PBGC.

(c) *Method of distribution.*

(1) *In general.* The plan administrator shall, in accordance with all applicable requirements under the Code and ERISA, distribute plan assets in satisfaction of all benefit liabilities (determined as of the termination date). In the case of benefit liabilities that must be provided in annuity form, the distribution shall be made by purchasing irrevocable commitments from an insurer selected in accordance with the fiduciary standards of Title I of ERISA.

(2) *Participating annuity contracts.* In the case of a plan in which any residual assets are to be distributed to participants, a participating annuity contract may be purchased to satisfy the requirement that annuities be provided by the purchase of irrevocable commitments only if the portion of the price of the contract that is attributable to the participation feature—

(i) Is not taken into account in determining the amount of residual assets; and

(ii) Is not paid from residual assets allocable to participants.

(3) *Missing participants.* The plan administrator shall distribute benefits to missing participants in accordance with part 4050.

(d) *Notice of annuity contract.* If benefit liabilities are provided through the purchase of irrevocable commitments—

(1) Either the plan administrator or the insurer shall, within 30 days after it is available, provide each participant and beneficiary with a copy of the annuity contract or certificate showing the insurer's name and address and clearly reflecting the insurer's obligation to provide the participant's or beneficiary's benefit; and

(2) If such a contract or certificate is not available on or before the date on which the post-distribution certificate is required to be filed in order to avoid the assessment of penalties under § 4041.29(b), the plan administrator shall, no later than such date, provide each participant and beneficiary with a written notice stating—

(i) That the obligation for providing the participant's or beneficiary's plan benefits has transferred to the insurer;

(ii) The name and address of the insurer;

(iii) The name, address, and telephone number of the person designated by the insurer to answer questions concerning the annuity; and

(iv) That the participant or beneficiary will receive from the plan administrator or insurer a copy of the annuity contract or a certificate showing the insurer's name and address and clearly reflecting the insurer's obligation to provide the participant's or beneficiary's benefit.

§ 4041.29 Post-distribution certification.

(a) *Deadline.* Within 30 days after the last distribution date for any affected party, the plan administrator shall file with the PBGC a post-distribution certification consisting of the PBGC Form 501, completed in accordance with the instructions thereto.

(b) *Assessment of penalties.* The PBGC will assess a penalty for late filing of a post-distribution certification only to the extent the certification is filed more than 90 days after the distribution deadline (including extensions) under § 4041.28(a).

§ 4041.30 Requests for deadline extensions.

(a) *In general.* In narrow circumstances, the PBGC may in its discretion extend a deadline for taking action under this subpart to a later date. The PBGC will grant such an extension where it finds compelling reasons why it is not administratively feasible for the plan administrator (or other persons acting on behalf of the plan administrator) to take the action until the later date and the delay is brief. The PBGC shall consider—

(1) The length of the delay; and

(2) Whether ordinary business care and prudence in attempting to meet the deadline is exercised.

(b) *Time of extension request.* Any request for an extension under paragraph (a) that is filed later than the 15th day before the applicable deadline shall include a justification for not filing the request earlier.

(c) *IRS determination letter requests.* Any request for an extension under paragraph (a) of the deadline in § 4041.25(c) for submitting a determination letter request to the IRS (in order to qualify for the distribution deadline in § 4041.28(a)(1)(ii)) shall be deemed to be granted unless the PBGC notifies the plan administrator otherwise within 60 days after receipt of the request (or, if later, by the end of the PBGC's review period under § 4041.26(a)). The PBGC shall notify the plan administrator in writing of the date on which it receives such request.

(d) *Statutory deadlines not extendable.* The PBGC may not—

(1) Extend the 60-day time limit under § 4041.23(a) for issuing the notice of intent to terminate;

(2) Waive the requirement in § 4041.24(a) that the notice of plan benefits be issued by the time the plan administrator files the standard termination notice with the PBGC; or

(3) Extend the deadline under § 4041.29(a) for filing the post-distribution certification. However, the PBGC will assess a penalty for late filing of a post-distribution certification only under the circumstances described in § 4041.29(b).

§ 4041.31 Notice of noncompliance.

(a) *Failure to meet pre-distribution requirements.*

(1) *In general.* Except as provided in paragraphs (a)(2) and (c), the PBGC shall issue a notice of noncompliance within the 60-day (or extended) time period prescribed by § 4041.26(a) whenever it determines that—

(i) The plan administrator failed to issue the notice of intent to terminate to all affected parties (other than the PBGC) in accordance with §§ 4041.23;

(ii) The plan administrator failed to issue notices of plan benefits to all affected parties entitled to plan benefits in accordance with § 4041.24;

(iii) The plan administrator failed to file the standard termination notice in accordance with § 4041.25;

(iv) As of the distribution date proposed in the standard termination notice, plan assets will not be sufficient to satisfy all benefit liabilities under the plan; or

(v) In the case of a spin-off/termination transaction (as described in § 4041.23(c)), the plan administrator failed to issue the notices required by § 4041.23(c), § 4041.24(f), and § 4041.27(a)(2).

(2) *Interests of participants.* The PBGC may decide not to issue a notice of noncompliance based on a failure to meet a requirement under paragraphs (a)(1)(i) through (a)(1)(iii) or (a)(1)(v) of this section if it determines that issuance of the notice would be inconsistent with the interests of participants and beneficiaries.

(3) *Continuing authority.* The PBGC may issue a notice of noncompliance or suspend the termination proceeding based on a failure to meet a requirement under paragraphs (a)(1)(i) through (a)(1)(v) of this section after expiration of the 60-day (or extended) time period prescribed by § 4041.26(a) (including upon audit) if the PBGC determines such action is necessary to carry out the purposes of Title IV.

(b) *Failure to meet distribution requirements.*

(1) *In general.* If the PBGC determines, as part of an audit or otherwise, that the plan administrator has not satisfied any distribution requirement of § 4041.28(a), it may issue a notice of noncompliance.

(2) *Criteria.* In deciding whether to issue a notice of noncompliance under paragraph (b)(1) of this section, the PBGC may consider—

(i) The nature and extent of the failure to satisfy a requirement of § 4041.28(a);

(ii) Any corrective action taken by the plan administrator; and

(iii) The interests of participants and beneficiaries.

(3) *Late distributions.* The PBGC shall not issue a notice of noncompliance for failure to distribute timely based on any facts disclosed in the post-distribution certification if 60 or more days have passed from the PBGC's receipt of the post-distribution certification.

(c) *Correction of errors.* The PBGC shall not issue a notice of noncompliance based solely on the plan administrator's inclusion of erroneous information (or omission of correct information) in a notice required to be provided to any person under this part if—

(1) The PBGC determines that the plan administrator acted in good faith in connection with the error;

(2) The plan administrator corrects the error no later than—

(i) In the case of an error in the notice of plan benefits under § 4041.24, the latest date an election notice may be provided to the person; or

(ii) In any other case, as soon as practicable after the plan administrator knows or should know of the error, or by any later date specified by the PBGC; and

(3) The PBGC determines that the delay in providing the correct information will not substantially harm any person.

(d) *Reconsideration.* A plan administrator may request reconsideration of a notice of noncompliance in accordance with the rules prescribed in part 4003, subpart C.

(e) *Consequences of notice of noncompliance.*

(1) *Effect on termination.* A notice of noncompliance ends the standard termination proceeding, nullifies all actions taken to terminate the plan, and renders the plan an ongoing plan. A notice of noncompliance is effective upon the expiration of the period within which the plan administrator may request reconsideration under paragraph (d) of this section or, if reconsideration is requested, a decision by the PBGC upholding the notice. However, once a notice is issued, the plan administrator shall take no further action to terminate the plan (except by initiation of a new termination) unless and until the notice is revoked pursuant to a decision by the PBGC on reconsideration. A plan administrator that still desires to terminate a plan shall initiate the termination process again, starting with the issuance of a new notice of intent to terminate.

(2) *Effect on plan administration.* If the PBGC issues a notice of noncompliance, the prohibitions in § 4041.22(a) shall cease to apply—

(i) Upon expiration of the period during which reconsideration may be requested or, if earlier, at the time the plan administrator decides not to request reconsideration; or

(ii) If reconsideration is requested, upon PBGC issuance of decision on reconsideration upholding the notice of noncompliance.

(f) *If no notice of noncompliance is issued.* A standard termination is deemed to be valid if—

(1) The plan administrator files a standard termination notice under § 4041.25 and the PBGC does not issue a notice of noncompliance pursuant to § 4041.31(a); and

(2) The plan administrator files a post-distribution certification under § 4041.29 and the PBGC does not issue a notice of noncompliance pursuant to § 4041.31(b).

(g) *Notice to affected parties.* Upon a decision by the PBGC on reconsideration affirming the issuance of a notice of noncompliance or, if earlier, upon the plan administrator's decision not to request reconsideration, the plan administrator shall notify the affected parties (other than the PBGC), and any persons who were provided notice under § 4041.23(c), in writing that the plan is not going to terminate or, if applicable, that the termination was invalid but that a new notice of intent to terminate is being issued.

§ 4041.41 [Amended]

7. Paragraph (a) of redesignated § 4041.41 is amended by removing the words ''Requirements for a distress termination'' and adding in their place, ''Distress requirements'' in the title.

8. Paragraph (a)(1) of redesignated § 4041.41 is amended by removing ''4041.41'' and adding in its place ''4041.43'' and by adding the words ''(except with PBGC approval)'' after ''and'' and before ''not''.

9. Paragraph (a)(2) of redesignated § 4041.41 is amended by removing ''4041.43'' and adding in its place ''4041.45'' and by removing the words ''or, if applicable, no later than the due date established in an extension notice issued under § 4041.8''.

10. Paragraphs (a)(3) and (e) of redesignated § 4041.41 are amended by removing ''paragraph (e)'' and adding in its place ''paragraph (c)''.

11. Paragraph (b)(1) of redesignated § 4041.41 is amended by removing the word ''If'' and adding in its place ''Except as provided in paragraph (b)(2)(i) of this section, if''; and by removing the words ''of paragraph (b) of this section for a standard termination or, except as provided in paragraph (d)(2)(i) of this section, all of the requirements of paragraph (c) of this section''

12. Paragraph (b)(2)(i) of redesignated § 4041.41 is amended by removing ''(c)(1)'' and adding in its place ''(a)(1)''; and by removing ''(c)(2)'' and adding in its place ''(a)(2)''.

13. Paragraphs (d)(1) and (d)(2) of redesignated § 4041.41 are amended by removing ''(e)(2)'' and adding in its place ''(c)(2)''.

14. Paragraphs(d)(1)(i), (d)(1)(iii), and (d)(2) of redesignated § 4041.41 are amended by removing ''(e)(3)'' and adding in its place ''(c)(3)''.

§ 4041.42 [Amended]

15. Redesignated § 4041.42 is amended by removing the words ''pendency of termination proceedings'' and adding in their place ''termination process'' in the title.

16. Paragraph (a) of redesignated § 4041.42 is amended by adding the word ''and'' after ''due the plan,''; and by removing the words ''and, during the pendency of a standard termination, making loans to participants,''.

17. Paragraph (b) of redesignated § 4041.42 is amended by removing the words ''in a distress termination'' in the title; and by removing ''4041.48'' and adding in its place ''4041.50''.

18. Paragraph (c) of redesignated § 4041.42 is amended by removing the words ''in a distress termination'' in the title.

19. Paragraph (d) of redesignated § 4041.42 is amended by removing ''4041.42(c)'' and adding in its place ''4041.44(c)''; and by removing ''4041.44(c)(1)'' and adding in its place ''4041.46(c)(1)''.

20. Paragraph (d)(1) of redesignated § 4041.42 is amended by removing ''(c)'' and adding in its place ''(b)''; and by removing ''(c)(1)'' and adding in its place ''(b)(1)''.

21. Paragraph (d)(1)(i) of redesignated § 4041.42 is amended by removing ''4041.42(e) and 4041.44(d)'' and adding in its place ''4041.44(e) and 4041.46(e)''.

22. Paragraph (d)(2) of redesignated § 4041.42 is amended by removing ''(f)'' and adding in its place ''(c)''.

23. Paragraph (e) of redesignated § 4041.42 is amended by removing ''4041.47(b)'' and adding in its place ''4041.49(b)''; by removing ''4041.47(d)'' and adding in its place ''4041.49(d)''; by removing ''(c)'' and adding in its place ''(b)''; and by removing ''4041.47(e)'' and adding in its place ''4041.49(e)''.

§ 4041.43 [Amended]

24. Paragraph (a)(3) of redesignated § 4041.43 is amended by removing ''(d)'' and adding in its place ''(b)''.

25. Paragraphs (b) and (c) of redesignated § 4041.43 are removed.

26. Paragraph (d) of redesignated § 4041.43 is redesignated as paragraph (b), and as so redesignated is amended by removing the words ''employer identification number (''EIN')'' and adding in their place ''EIN''; and by removing the words ''plan number ('PN')'' and adding in their place ''PN'' in paragraph (d)(2); by removing ''.'' and adding in its place '';'' in paragraph (d)(4); and by removing the words ''A statement that benefit and service accruals will continue until the termination date or, if applicable, that benefit accruals were or will be frozen as of a specific date in accordance with section 204(h) of ERISA'' and by adding in their place ''The cessation of accruals

information in § 4041.23(b)(4)'' in paragraph (d)(5).

27. Paragraph (e) of redesignated § 4041.43 is redesignated as paragraph (c) and as so redesignated is amended by removing ''4041.21(f)'' and adding in its place ''4041.23(c)''.

§ 4041.44 [Amended]

28. In redesignated § 4041.44, paragraphs (a)(1), (b), and (c) are amended by removing ''4041.41'' and adding in its place ''4041.43''.

29. Paragraph (b)(3) of redesignated § 4041.44 is amended by removing ''4041.43'' and adding in its place ''4041.45''.

30. Paragraph (c) of redesignated § 4041.44 is amended by removing ''4041.3(d)(2)(i)'' and adding in its place ''4041.41(b)(2)(i)''.

31. Paragraph (f) of redesignated § 4041.44 is amended by removing ''4041.41(e))'' and adding in its place ''4041.43(e))''; and by removing the sentence ''The notice required by this paragraph shall be provided in the manner described in § 4041.26(d)(2).''.

§ 4041.45 [Amended]

32. Paragraph (b)(1)(ii) of redesignated § 4041.45 is amended by removing ''4041.44(b)'' and adding in its place ''4041.46(b)''.

33. Redesignated § 4041.45(d) is removed.

§ 4041.46 [Amended]

34. Paragraphs (a) and (b) of redesignated § 4041.46 are amended by removing ''4041.3(c)'' and adding in its place ''4041.41(c)''.

35. Paragraph (b) of redesignated § 4041.46 is amended by removing ''4041.43(b)'' and adding in its place ''4041.45(b)''.

36. Paragraph (c)(1) of redesignated § 4041.46 is amended by removing ''4041.3(c)'' and adding in its place ''4041.41''; and by removing ''4041.3(d)'' and adding in its place ''4041.41(b)''.

37. Paragraph (c)(2) of redesignated § 4041.46 is amended by removing the words '', or, if applicable, no later than the due date established in an extension notice issued under § 4041.8''.

38. Paragraph (e) of redesignated § 4041.46 is amended by removing ''4041.41(e)'' and adding in its place ''4041.43(e)''; and by removing the sentence ''The notice required by this paragraph shall be provided in the manner described in § 4041.26(d)(2).''

§ 4041.47 [Amended]

39. Paragraph (a) of redesignated § 4041.47 is amended by removing ''4041.43(b)(1)'' and adding in its place ''4041.45(b)(1)''.

40. Paragraph (b)(1) of redesignated § 4041.47 is amended by removing ''4041.4'' and adding in its place ''4041.42''.

41. Paragraph (c)(1) of redesignated § 4041.47 is amended by removing ''4041.46'' and adding in its place ''4041.48''.

42. Paragraph (c)(2) of redesignated § 4041.47 is amended by removing ''4041.48'' and adding in its place ''4041.50''.

43. Paragraph (c)(3) of redesignated § 4041.47 is amended by removing ''4041.48(b)'' and adding in its place ''4041.50(b)''.

44. Paragraph (c)(4) of redesignated § 4041.47 is amended by removing ''4041.11'' and adding in its place ''4041.5''.

45. Redesignated § 4041.47 is amended by adding a new paragraph (d) to read as follows:

§ 4041.47 PBGC determination of plan sufficiency/insufficiency.

* * * * *

(d) *Alternative treatment of majority owner's benefit.* A majority owner may elect to forego receipt of all or part of his or her benefit in connection with a distress termination. Any such alternative treatment—

(1) Is valid only if the conditions in § 4041.21(b)(2)(i) through (iii) are met; and—

(2) Is subject to the PBGC's approval if the election—

(i) Is made after the termination date; and

(ii) Would result in the PBGC determining that the plan is sufficient for guaranteed benefits under paragraph (c).

46. § 4041.48 is revised to read as follows:

§ 4041.48 Sufficient plans; notice requirements.

(a) *Notices of benefit distribution.* When a distribution notice is issued by the PBGC pursuant to § 4041.47, the plan administrator shall issue notices of benefit distribution in accordance with the rules regarding notice of plan benefits in § 4041.24, except that—

(1) The deadline for issuing the notices of benefit distribution is the 60th day after receipt of the distribution notice; and

(2) With respect to the information described in § 4041.24(b), the terms ''plan benefits'' and ''pension benefits'' are replaced with ''Title IV benefits'' and the term ''proposed termination date'' is replaced with ''termination date''.

(b) *Certification to PBGC.* No later than 15 days after the date on which the plan administrator completes the issuance of the notices of benefit distribution, the plan administrator shall file with the PBGC a certification that the notices were so issued in accordance with the requirements of this section.

(c) *Notice of annuity information.* (1) *In general.* Unless all plan benefits will be distributed in the form of nonconsensual lump sums, the plan administrator shall provide a notice of annuity information to each affected party other than—

(i) An affected party whose plan benefits will be distributed in the form of a nonconsensual lump sum; and

(ii) The PBGC.

(2) *Spin-off/termination transactions.* The plan administrator shall provide the information in paragraph (c)(4) of this section to a person entitled to notice under § 4041.43(c), at the same time and in the same manner as required for an affected party described in paragraph (c)(1) of this section.

(3) *Selection of different insurer.* A plan administrator that decides to select a different insurer after having previously notified the affected party of the identity of insurer(s) under this paragraph shall provide another notice of annuity information.

(4) *Content of notice.* The notice shall include—

(i) The identity-of-insurer information in § 4041.27(b)(1);

(ii) The information regarding change in identity of insurer(s) in § 4041.27(b)(2); and

(iii) Unless the state guaranty coverage information in § 4041.27(b)(3) was previously provided to the affected party, such information and the extinguishment-of-guaranty information in § 4041.23(b)(8) (replacing the term ''pension benefits'' with ''Title IV benefits'').

(5) *Deadline for notice.* The plan administrator shall issue the notice of annuity information to each affected party by the deadline in § 4041.27(d)(1).

(d) *Request for IRS determination letter.* To qualify for the distribution deadline in § 4041.28(a)(1)(ii) (as modified and made applicable by § 4041.50(c)), the plan administrator shall submit to the IRS a valid request for a determination of the plan's qualification status upon termination (''determination letter'') by the day on which the plan administrator completes the issuance of the notices of benefit distribution.

§ 4041.49 [Amended]

47. Paragraphs (a) and (c) of redesignated § 4041.49 are amended by

removing ''4041.48'' and adding in its place ''4041.50''.

48. Paragraph (b)(1)(i) of redesignated § 4041.49 is amended by removing ''4041.45(b)'' and adding in its place ''4041.47(b)''.

49. Paragraph (e) of redesignated § 4041.49 is amended by removing ''4041.4(c)'' and adding in its place ''4041.42''.

50. § 4041.50 is added to read as follows:

§ 4041.50 Closeout of plan.

If a plan administrator receives a distribution notice from the PBGC pursuant to § 4041.47 and neither the plan administrator nor the PBGC makes the finding described in § 4041.49(b) or (d), the plan administrator shall distribute plan assets in accordance with § 4041.28 and file a post-distribution certification in accordance with § 4041.29, except that—

(a) The term ''benefit liabilities'' is replaced with ''Title IV benefits'';

(b) For purposes of applying the distribution deadline in § 4041.28(a)(1)(i), the phrase ''after the expiration of the PBGC's 60-day (or extended) review period under § 4041.26(a)'' is replaced with ''the day on which the plan administrator completes the issuance of the notices of benefit distribution pursuant to § 4041.48(a)''; and

(c) For purposes of applying the distribution deadline in § 4041.28(a)(1)(ii), the phrase ''the requirements of § 4041.25(c)'' is replaced with ''the requirements of § 4041.48(d)''.

PART 4001—TERMINOLOGY

51. The authority citation for Part 4001 continues to read as follow:

Authority: 29 U.S.C. 1301, 1302(b)(3).

§ 4001.2 [Amended]

52. In § 4001.2, paragraph (2) of the definition of *Distribution date* is amended by removing the words ''Other than for purposes of determining the interest rate to be used in calculating the value of a benefit to be paid as a lump sum to a late-discovered participant, the'' and adding in their place ''The''; and by removing the words ''PBGC, a benefit provided after the deemed distribution date to a late-discovered participant, or an irrevocable commitment purchased from an insurer after the deemed distribution date for a recently-missing participant'' and adding in their place the word ''PBGC''.

PART 4006—PREMIUM RATES

53. The authority citation for Part 4006 continues to read as follow:

Authority: 29 U.S.C. 1302(b)(3), 1306, 1307.

§ 4006.5 [Amended]

54. In § 4006.5, paragraph (f)(3) is amended by removing the words ''or, if later (in the case of a single-employer plan), the date 30 days prior to the date the PBGC receives the plan's post-distribution certification''.

PART 4050—MISSING PARTICIPANTS

55. The authority citation for Part 4050 is added to read as follow:

Authority: 29 U.S.C. 1302(b)(3), 1350.

§ 4050.1 [Amended]

56. In § 4050.1, the reference ''§ 4041.27(c)'' is removed and the reference ''§ 4041.28(c)'' is added in its place.

57. In § 4050.2, the definition of *Late-discovered participant* is removed; the definition of *Recently-missing participant is* removed; the definition of *Post-distribution certification* is amended by removing the words ''§ 4041.27(h) or § 4041.48(b)'' and adding in their place the words ''§ 4041.29 or § 4041.50''; and the definition of *Deemed distribution date* is revised to read as follows:

§ 4050.2 Definitions.

* * * * *

Deemed distribution date ordinarily means the last day of the period in which distribution may be made (determined without regard to the provisions of this part) under part 4041 of this chapter. The plan administrator may select an earlier date, provided that the selected date is no earlier than the date when all benefit distributions have been made under the plan except for distributions to missing participants whose designated benefits are paid to the PBGC.

* * * * *

§ 4050.3 [Amended]

58. In § 4050.3, paragraph (a) is amended by removing the words ''§ 4041.27(c) or § 4041.48(a)(1)'' and adding in their place the words ''§ 4041.28(c) or § 4041.50''.

59. In § 4050.4, paragraph (b)(1) is amended by removing the words ''(or, in the case of a recently-missing participant, on or before the 90th day after the deemed distribution date)''; and paragraph (a) is revised to read as follows:

§ 4050.4 Diligent search.

(a) *Search required.* A diligent search shall be made for each missing participant before information about the missing participant or payment is submitted to the PBGC pursuant to § 4050.6.

* * * * *

60. In § 4050.6, paragraphs (a)(2) and (a)(3) are removed; paragraph (a)(1) is redesignated as paragraph (a), the heading is revised as set forth below, and the reference ''§ 4041.9'' is revised to read ''§ 4041.3(b)'; paragraph (b) is amended by removing the words ''If the plan administrator'' and adding in their place the words ''Except as provided in paragraph (b)(2) of this section, if the plan administrator'; the heading and text of paragraph (b) (as so amended) are redesignated as paragraph (b)(1); a new heading is added to paragraph (b), and new paragraph (b)(2) is added, to read as follows:

§ 4050.6 Payment and required documentation.

(a) *Time of payment and filing.*

* * * * *

(b) *Late charges.*

(1) *Interest on late payments.* * * *

(2) *Assessment of interest and penalties.* The PBGC will assess interest for late payment of a designated benefit or a penalty for late filing of information only to the extent paid or filed beyond the time provided in § 4041.29(b).

* * * * *

§ 4050.7 [Amended]

61. In § 4050.7, paragraph (a) is amended by removing the words ''the insurer and the relevant policy number'' and adding in their place the words ''the insurer, the relevant policy number, and (to the extent known) the amount or value of the benefit''.

§ 4050.12 [Amended]

62. In § 4050.12, paragraphs (a) and (h) are removed and paragraphs (b), (c), (d), (e), (f), (g), and (i) are redesignated as paragraphs (a), (b), (c), (d), (e), (f), and (g) respectively; redesignated paragraph (a) is amended by removing the words ''treat the missing participant like a late-discovered participant'' and adding in their place the words ''make distribution to the individual in such manner as the PBGC shall direct''; redesignated paragraph (c) is amended by removing the references ''paragraph (d)(2)'', ''paragraph (d)(2)(i)'', and ''paragraph (d)(2)(ii)'' and adding in their place the references ''paragraph (c)(2)'', ''paragraph (c)(2)(i)'', and ''paragraph (c)(2)(ii)'' respectively; and redesignated paragraph (g) is amended by removing the reference ''paragraph

(i)'' in both places where it appears and adding in each place the reference ''paragraph (g)''.

§ 4050.13 [Removed]

63. Section 4050.13 is removed.

Issued in Washington, DC, this 11th day of March, 1997.

John Seal,

Acting Executive Director, Pension Benefit Guaranty Corporation.

[FR Doc. 97–6500 Filed 3–13–97; 8:45 am]

BILLING CODE 7708–01–P

PENSION BENEFIT GUARANTY CORPORATION

29 CFR Part 4041

Assessment of Penalties for Failure to Provide Required Information

AGENCY: Pension Benefit Guaranty Corporation.

ACTION: Statement of policy.

SUMMARY: In order to provide penalty relief, the Pension Benefit Guaranty Corporation is announcing a new penalty policy. Under the new policy, the PBGC will not assess a penalty if a post-distribution certification is filed within 90 days after the deadline for completing distributions. Plan administrators are required to file these certifications in standard terminations and in sufficient distress terminations.

DATES: The revised policy takes effect on March 14, 1997 with respect to any matter for which a notice of final penalty assessment has not been issued as of that date.

FOR FURTHER INFORMATION CONTACT: Harold J. Ashner, Assistant General Counsel, Office of the General Counsel, or Catherine B. Klion, Attorney, Pension Benefit Guaranty Corporation, 1200 K Street, NW., Washington, DC 20005–4026; 202–326–4024 (202–326–4179 for TTY and TDD).

SUPPLEMENTARY INFORMATION: Under the Employee Retirement Income Security Act of 1974, a plan administrator must file a post-distribution certification with the PBGC within 30 days after the final distribution of assets (other than excess assets) in a standard termination or in a distress termination in which the plan is sufficient for at least guaranteed benefits. Practitioners have expressed concerns to the PBGC about their difficulties in meeting this certification deadline. In many cases, the plan administrator is not the person who distributes assets and thus may not know when the final distribution is made.

Failure to file a post-distribution certification on time may result in assessment of a penalty under section 4071 of ERISA. In addition, a late certification may result in the loss of (1) part or all of the plan's premium refund for its final short plan year (see 29 CFR 4006.5(f)(3)), and (2) the 30-day (or, in the case of a recently missing participant, 120-day) interest-free grace period for late payment of a designated benefit for a missing participant (see 29 CFR 4050.6).

Elsewhere in today's Federal Register, the PBGC is proposing a number of revisions to its termination regulation that, among other things, address the above concerns. Under the proposed rule, the PBGC will assess a penalty for a late post-distribution certification only to the extent the certification is filed more than 90 days after the distribution deadline (including extensions).

For example, if the distribution deadline is March 1, and the final distribution of assets is made January 15, the post-distribution certification is due February 14 (before the distribution deadline). Under the proposed rule, the PBGC will not assess a penalty for a late post-distribution certification if the certification is filed by May 30 (90 days after March 1). If the certification is filed May 31, the PBGC will treat the filing as being only one day late for penalty assessment purposes.

The proposed rule provides the same penalty relief for the late filing of certain information under the missing participants program (see 29 CFR 4050.6(a)). It also eliminates the reduction resulting from a late post-distribution certification in the premium refund for a short plan year and waives interest for late payment of a missing participant's designated benefit throughout the period in which the post-distribution certification may be filed without penalty.

Effective immediately, the PBGC is implementing a policy under which it will apply the above rules regarding penalties for late filing of a post-distribution certification and other information. Pending the completion of the rulemaking on the PBGC's termination regulation, the provisions in the existing regulation regarding premium refunds for a short plan year and interest for late payment of a missing participant's designated benefit remain in effect.

The PBGC will continue to apply the penalty and reasonable cause guidelines and procedural requirements referred to in its July 18, 1995, policy statement.

Issued in Washington, DC, this 11th day of March, 1997.

John Seal,

Acting Executive Director, Pension Benefit Guaranty Corporation.

[FR Doc. 97–6499 Filed 3–13–97; 8:45 am]

BILLING CODE 7708–01–P

federal register

Friday
March 14, 1997

Part IV

Department of the Interior

Fish and Wildlife Service

50 CFR Part 20

Migratory Bird Harvest Information Program; Participating States for the 1997–98 Season; Proposed Rule

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

50 CFR Part 20

RIN 1018–AE13

Migratory Bird Harvest Information Program; Participating States for the 1997–98 Season

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Proposed rule.

SUMMARY: The Fish and Wildlife Service (hereinafter Service) herein proposes to amend the Migratory Bird Harvest Information Program (hereinafter Program) regulations. The Service plans to add Arizona, Florida, Kentucky, North Carolina, and Texas (beginning with the 1997–98 hunting season) to the list of participating States. This regulatory action will continue to require all licensed hunters who hunt migratory game birds in participating States to register as migratory game bird hunters and provide their name, address, and date of birth to the State licensing authority. Hunters will be required to have evidence of current participation in the Program on their person while hunting migratory game birds in participating States. The quality and extent of information about harvests of migratory game birds must be improved in order to better manage these populations. Hunters' names and addresses are necessary to provide a sample frame for voluntary hunter surveys to improve harvest estimates for all migratory game birds. States will gather migratory bird hunters' names and addresses and the Service will conduct the harvest surveys.

DATES: The written comment period for the proposed rule will end on May 13, 1997.

ADDRESSES: Written comments should be sent to the Chief, Office of Migratory Bird Management, U.S. Fish and Wildlife Service, 10815 Loblolly Pine Drive, Laurel, Maryland 20708–4028. Comments received will be available for public inspection during normal business hours in Building 158, 10815 Loblolly Pine Drive (Gate 4, Patuxent Wildlife Research Center), Laurel, Maryland 20708–4028.

FOR FURTHER INFORMATION CONTACT: Paul I. Padding, Office of Migratory Bird Management, U.S. Fish and Wildlife Service, 10815 Loblolly Pine Drive, Laurel, Maryland 20708–4028, (301) 497–5980, FAX (301) 497–5981.

SUPPLEMENTARY INFORMATION: The purpose of this rule is to expand the Program to include the States of Arizona, Florida, Kentucky, North Carolina, and Texas beginning in the 1997–98 hunting season.

Background

The purpose of this cooperative Program is to annually obtain a nationwide sample frame of migratory bird hunters, from which representative samples of hunters will be selected and asked to participate in voluntary harvest surveys. State wildlife agencies will provide the sample frame by annually collecting the name, address, and date of birth of each licensed migratory bird hunter in the State. To reduce survey costs and to identify hunters who hunt less commonly-hunted species, States will also request that each migratory bird hunter provide a brief summary of his or her migratory bird hunting activity for the previous year. States will send this information to the Service, and the Service will sample hunters and conduct national hunter activity and harvest surveys.

A notice of intent to establish the Program was published in the June 24, 1991, Federal Register (56 FR 28812). A final rule that established the Program and initiated a 2-year pilot phase in three volunteer States (California, Missouri, and South Dakota) was published in the March 19, 1993, Federal Register (58 FR 15093). The pilot phase was completed following the 1993–94 migratory bird hunting seasons in California, Missouri, and South Dakota.

A State/Federal technical group was formed to evaluate Program requirements, the different approaches used by the pilot States, and the Service's survey procedures during the pilot phase. Changes incorporated into the Program as a result of the technical group's evaluation were specified in a final rule, published in the October 21, 1994, Federal Register (59 FR 53334), that initiated the implementation phase of the Program.

Currently, all licensed hunters who hunt migratory game birds in participating States are required to have a Program validation, indicating that they have identified themselves as migratory bird hunters and have provided the required information to the State wildlife agency. Hunters must provide the required information to each State in which they hunt migratory birds. Validations are printed on or attached to the annual State hunting license or on a State-specific supplementary permit. The State may charge hunters a handling fee to compensate hunting-license agents and to cover the State's administrative costs for the Program.

The State/Federal technical group continues to evaluate the Program to determine the adequacy and timeliness of the sample frame and the time burden, cost, and other impacts on hunters, State license agents, State wildlife agencies, and the Service. Emphasis is currently on the time requirement for the sample frame and on alternative survey methods for special groups of unlicensed hunters (e.g., junior and senior hunters).

The Service's survey design calls for hunting-record forms to be distributed to hunters selected for the survey before they forget the details of their hunts. Because of this design requirement, States have only a short time to obtain hunter names and addresses from license vendors and to provide those names and addresses to the Service. Currently, participating States must send the required information to the Service within 30 calendar days of issuance of the hunting license or permit.

The Service has requested the cooperation of participating States to facilitate obtaining harvest estimates for hunters who are exempted from a permit requirement and those that are also exempted from State licensing requirements. This includes several categories of hunters such as junior hunters, senior hunters, landowners, and other special categories. Because exemptions and the methods for obtaining harvest estimates for exempt groups vary from State to State, the Service will incorporate these methods into individual memoranda of understanding with participating States.

Excluding from the Program those hunters who are not required to obtain an annual State hunting license also excludes their harvest from the estimates. The level of importance of the excluded harvest on the resulting estimates depends on how many hunters are excluded and on the number of birds they bag. If the level of importance is significant, excluding these hunters will result in serious bias. Minimum survey standards are being developed for exempted categories. States may require exempted hunters to obtain permits (e.g., Maryland required exempted hunters to obtain permits upon entry to the Program in 1994).

Previously, the Service stated that States will continue to be added to the Program until all States participate in 1998. A suggested implementation schedule was published in the October 21, 1994, Federal Register (59 FR 53334), and was revised in a final rule published in the August 30, 1996, Federal Register (61 FR 46350). Ohio has requested a one-year delay to enable the State to implement improved license procedures that will better accommodate the Program.

Proposed Modifications to the Program

In addition to implementation of the Program in Arizona, Florida, Kentucky, North Carolina, and Texas, the Service proposes to modify the Program's implementation schedule by granting a one-year delay to Ohio.

NEPA Consideration

The establishment of the Harvest Information Program and options have been considered in the ''Environmental Assessment: Migratory Bird Harvest Information Program.'' Copies of this document are available from the Service at the address indicated under the caption **FOR FURTHER INFORMATION CONTACT.**

Regulatory Flexibility Act

On June 14, 1991, the Assistant Secretary for Fish and Wildlife and Parks concluded that the rule would not have a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*). This rule will eventually affect about 3–5 million migratory game bird hunters when it is fully implemented. It will require licensed migratory game bird hunters to identify themselves and to supply their names, addresses, and birth dates to the State licensing authority. Additional information will be requested in order that they can be efficiently sampled for a voluntary national harvest survey. Hunters will be required to have evidence of current participation in the Program on their person while hunting migratory game birds.

The States may require a handling fee to cover their administrative costs. Many of the State hunting-license vendors are small entities, but this rule should not economically impact those vendors. Only migratory game bird hunters, individuals, would be required to provide this information, so this rule should not adversely affect small entities.

Collection of Information: Migratory Bird Harvest Information Program

As required by the Paperwork Reduction Act of 1995 (44 U.S.C. 3507 (d)), the U.S. Fish and Wildlife Service has received approval for this collection of information, with approval number 1018–0015, with the expiration date of August 31, 1998.

The information to be collected includes: the name, address, and date of birth of each licensed migratory bird hunter in each participating State. Hunters' names, addresses, and other information will be used to provide a sample frame for voluntary hunter surveys to improve harvest estimates for all migratory game birds. The Service needs and uses the information to improve the quality and extent of information about harvests of migratory game birds in order to better manage these populations.

All information is to be collected once annually from licensed migratory bird hunters in participating States by the State license authority. Participating States are required to forward the hunter information to the Service within 30 calendar days of license or permit issuance. Annual reporting and record-keeping burden for this collection of information is estimated to average 0.015 hours per response for 2,090,000 respondents, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Thus, the total annual reporting and record-keeping burden for this collection is estimated to be 31,350 hours. Organizations and individuals desiring to submit comments on the information collection requirements should direct them to the Service Information Collection Clearance Officer, ms 224—ARLSQ, U.S. Fish and Wildlife Service, 1849 C Street, NW., Washington, DC 20240, or the Office of Management and Budget, Paperwork Reduction Project 1018–0015, Washington, DC 20503.

The Department considers comments by the public on this proposed collection of information in--

(1) Evaluating 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;

(2) Evaluating the accuracy of the Department's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

(3) Enhancing the quality, usefulness, and clarity of the information to be collected; and

(4) Minimizing the burden or the collection of information on those who are to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g., permitting electronic submission of responses.

OMB is required to make a decision concerning the collection of information contained in these proposed regulations between 30 and 60 days after publication of this document in the Federal Register. Therefore, a comment to OMB is best assured of having its full effect if OMB receives it within 30 days of publication. This does not effect the deadline for the public to comment to the Department on the proposed regulations.

Executive Order 12866

This rule was not subject to Office of Management and Budget review under Executive Order 12866.

Unfunded Mandates

The Service has determined and certifies pursuant to the Unfunded Mandates Act, 2 U.S.C. 1502 *et seq.*, that this rulemaking will not impose a loss of $100 million or more in any given year on local or state governments or private entities.

Civil Justice Reform

The Department has determined that these proposed regulations meet the applicable standards provided in Sections 3(a) and 3(b)(2) of Executive Order 12988.

Authorship

The primary author of this rule is Paul I. Padding, Office of Migratory Bird Management.

List of Subjects in 50 CFR Part 20

Exports, Hunting, Imports, Reporting and record keeping requirements, Transportation, Wildlife.

For the reasons set out in the preamble, 50 CFR part 20 is proposed to be amended as set forth below.

PART 20—MIGRATORY BIRD HUNTING

1. The authority citation for part 20 continues to read as follows:

Authority: 16 U.S.C. 703–711, 16 U.S.C. 712, and 16 U.S.C. 742 a—j.

2. In Section 20.20 paragraphs (a), (b) and (e) are revised to read as follows:

§ 20.20 Migratory Bird Harvest Information Program.

(a) *Information collection requirements*. The collections of information contained in § 20.20 have been approved by the Office of Management and Budget under 44 U.S.C. 3501 *et seq.* and assigned clearance number 1018–0015. The information will be used to provide a sampling frame for the national Migratory Bird Harvest Survey. Response is required from licensed hunters to obtain the benefit of hunting migratory game birds. Public reporting burden for this information is estimated to average 0.015 hours per response for 2,090,000 respondents, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Thus, the total annual reporting and record-keeping burden for this collection is estimated to be 31,350 hours. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing the burden, to the Service Information Collection Clearance Officer, MS-224 ARLSQ, Fish and Wildlife Service, Washington, DC 20240, or the Office of Management and Budget, Paperwork Reduction Project 1018–0015, Washington, DC 20503.

(b) *General provisions.* Each person hunting migratory game birds in Alabama, Arizona, California, Florida, Georgia, Idaho, Illinois, Kentucky, Maine, Maryland, Michigan, Minnesota, Mississippi, Missouri, North Carolina, Oklahoma, Oregon, Pennsylvania, South Dakota, Tennessee, Texas, and Vermont shall have identified himself or herself as a migratory bird hunter and given his or her name, address, and date of birth to the respective State hunting licensing authority and shall have on his or her person evidence, provided by that State, of compliance with this requirement.

* * * * *

(e) *Implementation schedule.* The Service is completing the implementation of this Program in 1998, which will incorporate approximately 1.3 million additional migratory bird hunters. It is proposed that the following States participate in 1998:

—Alaska, Arkansas, Colorado, Connecticut, Delaware, Indiana, Iowa, Kansas, Louisiana, Massachusetts, Montana, Nebraska, Nevada, New Hampshire, New Jersey, New Mexico, New York, North Dakota, Ohio, Rhode Island, South Carolina, Utah, Virginia, Washington, West Virginia, Wisconsin, and Wyoming.

Dated: March 5, 1997.

Don Barry,

Deputy Assistant Secretary for Fish and Wildlife and Parks.

[FR Doc. 97–6485 Filed 3–13–97; 8:45 am]

BILLING CODE: 4310–55–F

federal register

Friday
March 14, 1997

Part V

The President

Executive Order 13039—Exclusion of the Naval Special Warfare Development Group From the Federal Labor-Management Relations Program

Federal Register
Vol. 62, No. 50
Friday, March 14, 1997

Presidential Documents

Title 3—

The President

Executive Order 13039 of March 11, 1997

Exclusion of the Naval Special Warfare Development Group From the Federal Labor-Management Relations Program

By the authority vested in me as President by the Constitution and the laws of the United States of America, including section 7103(b)(1) of title 5 of the United States Code, and having determined that the Naval Special Warfare Development Group has as a primary function intelligence, counter-intelligence, investigative, or national security work and that the provisions of Chapter 71 of title 5 of the United States Code cannot be applied to this organization in a manner consistent with national security requirements and considerations, Executive Order 12171 of November 19, 1979, as amended, is further amended by adding the following at the end of section 1-205:

''(i) Naval Special Warfare Development Group.''

THE WHITE HOUSE,
March 11, 1997.

[FR Doc. 97–6703
Filed 3–13–97; 8:45 am]
Billing code 3195–01–P

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